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Chapter 2 - Need for Electric System Improvements in Wisconsin

Introduction

This chapter provides information about the transmission system of Wisconsin and the Upper Midwest region. It includes a description of the transmission system, some historical context, and a discussion of population and employment growth and their impact on the need for new transmission lines. Loss-of-load-expectation (LOLE) analysis, which allows quantification of the need for system improvements, is presented, followed by a discussion of possible sources of uncertainty in the LOLE calculation. A discussion of a number of additional benefits of system improvement is presented next. These benefits include reduction of system operating problems, increased access to economy power, and improved competitiveness of the electricity market by diluting prospective horizontal market power of the large generation owners in the state. The chapter concludes with a discussion of changes currently underway in the electric power industry, which are largely driven by changes in state and federal law. Of particular note are the changes in system operation and management expected under the coming Midwest Independent System Operator (ISO), and the development of a transmission company that will take over ownership and operation of virtually all of the eastern Wisconsin transmission system, including WPSC's transmission facilities.

The analysis in this chapter examines various aspects of the need for the proposed line. In some cases, the analysis and discussion bearing on one aspect of the need for the line may arrive at a particular observation. These singular observations should not be taken out of context. The complexity, size, and scope of the Arrowhead-Weston Transmission Project project require a balanced consideration of all the important factors.

Overview of existing transmission system

Figure 2-1 shows the existing high-voltage transmission system in Wisconsin. (See also Figure Vol. 2-11.) This map shows all transmission lines in voltage classes above 100 kV. The power-carrying ability of a line depends on a wide range of factors. In general, however, the higher a line's voltage, the stronger a connection it forms and the more power it can carry.

This figure shows that while western and eastern Wisconsin are each served by a well-connected electrical network, there are few connections between them. This situation is the result of the historical development of the power system. As electricity demand, generation, and the need for electrical interconnection grew, utilities built connections to their neighbors, and the growing networks eventually coalesced into well-connected regions. While eastern Wisconsin utilities built strong connections to Illinois, western Wisconsin utilities focused on connections to Minnesota and Iowa.

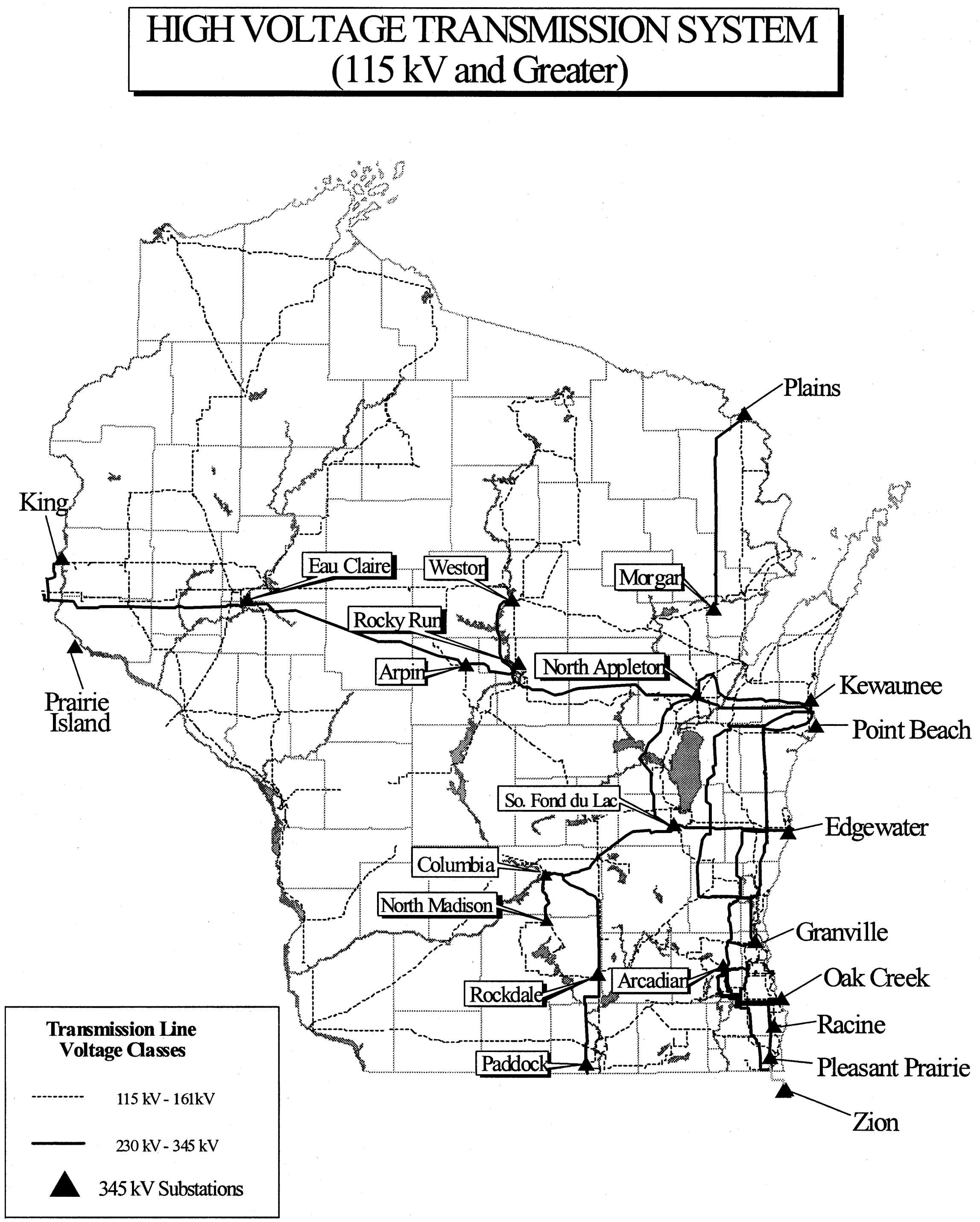
This split is reflected in the fact that Wisconsin utilities are divided into two different regional reliability councils, which are organizations formed by utilities to promote reliability across large regions. Western Wisconsin utilities are part of the Mid-Continent Area Power Pool (MAPP), which includes Minnesota, Iowa, Nebraska, the Dakotas, Manitoba, and Saskatchewan. Eastern Wisconsin utilities are part of the Mid-America Interconnected Network (MAIN), which includes Illinois and part of Missouri, as well as part of Michigan's Upper Peninsula.

Recently the MAIN and MAPP reliability councils have begun discussions to merge into a single Midwest Reliability Organization (MRO). A decision and vote of the members of MAIN and MAPP is expected in the Fall of 2000. A favorable vote would allow the new MRO to become effective January 1, 2001.

The few lines connecting eastern and western Wisconsin form, in essence, a weak link in the regional transmission network. The most important line connecting the two regions is the 345 kV line between the King power plant on the Minnesota shore of the St. Croix River and the North Appleton substation. The present-day power system is particularly sensitive to outages of this line. If parts of this line trip unexpectedly (i.e. are removed from service by protective circuit breakers) the system experiences significant impacts as the pattern of power flow on the transmission network is forced to change.

Under some circumstances, such a line outage can cause instability in the power system, threatening reliability of electric service. Power system operators manage this risk by limiting the amount of power that flows through the network. As a consequence, the potential for an outage of this cross-state transmission connection significantly reduces the transmission transfer capability (that is, the ability of the system to move power) into Wisconsin. Because outages of the King-North Appleton line are among the most severe problems faced by the regional power system, no amount of upgrading of the King-North Appleton line itself can eliminate the problem. Rather, it is necessary to provide alternative means to provide power when this line is out of service.

Figure 2-1 High-voltage transmission system in Wisconsin, including all lines in voltage classes above 100 kV



Depicts existing lines and those currently under construction

Figure 2-2 shows the transmission system in Wisconsin and several surrounding states. (See also Figure Vol. 2-12.) All lines that operate at voltages above 200 kV, a category known as extra-high-voltage (EHV) transmission, are included. This figure shows that many of these states have more extensive transmission infrastructure than does Wisconsin, and that all of the surrounding states have more EHV connections to neighboring states than does Wisconsin. This fact is sometimes regarded as evidence that Wisconsin needs to build more EHV transmission interconnections.

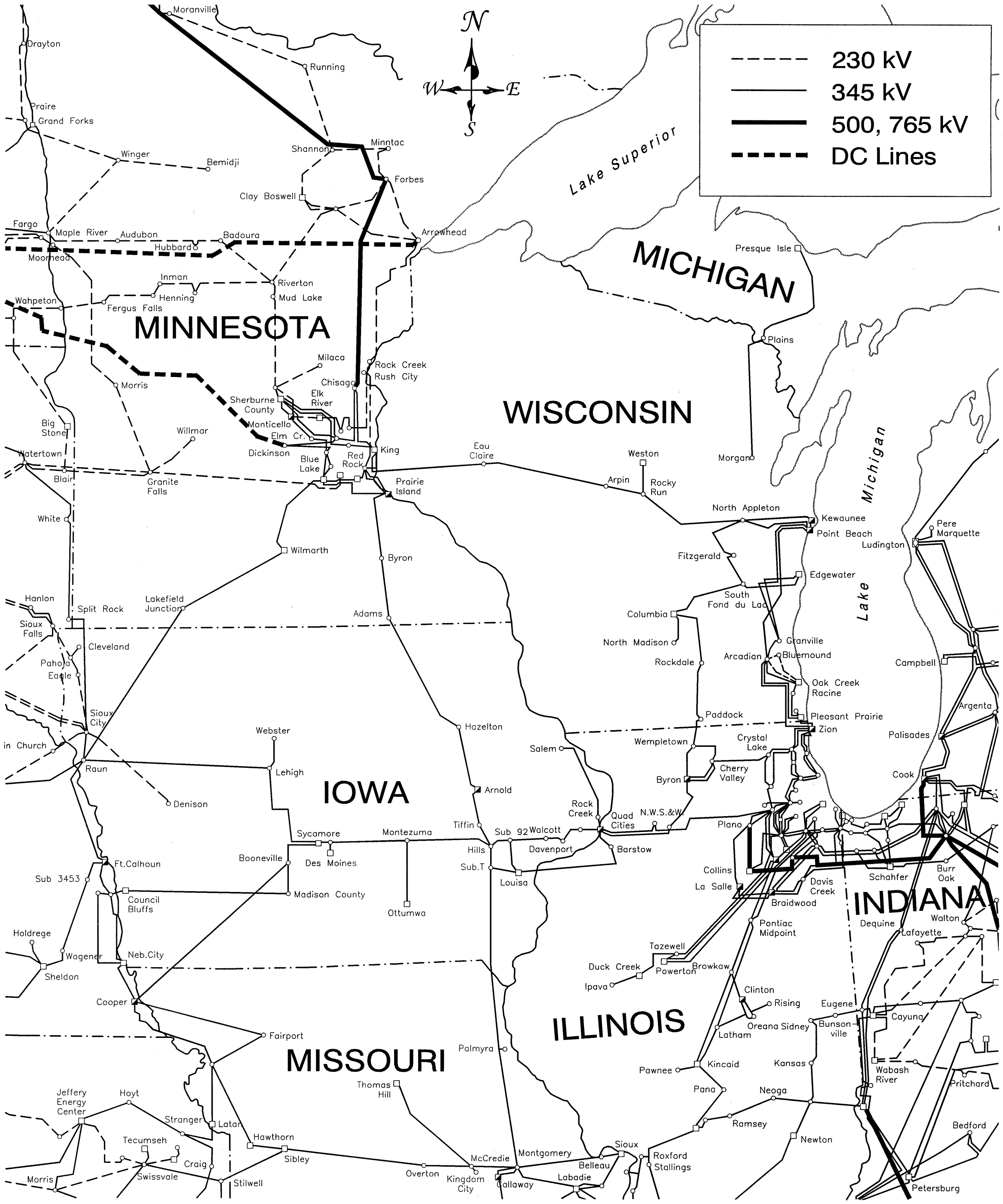
In assessing this argument, it is important to bear in mind that a number of factors influence system design, and a broad range of power system characteristics – beyond the number and length of high-voltage lines – plays a role in the performance of the transmission network. For example, Wisconsin's relatively small number of EHV interconnections is in part a consequence of geography. With Lake Michigan to the east and Lake Superior to the north, Wisconsin has less opportunity than most states to build connections to its neighbors.

The need for transmission connections is also a function of the pattern of generation and demand in an area. Some states have generation capability that is significantly higher than in-state electric demand. North Dakota, for example, exports a large amount of power, much of which is generated from abundant local coal resources. Accordingly, North Dakota's transmission system includes a large number of interconnections to its neighbors, which are necessary to accommodate these substantial power exports.

Wisconsin has power plants near most population centers, and these plants have generating capacity roughly comparable to the local electricity demand. In contrast, nearby states to the south and east of Wisconsin rely more heavily on large power plants and strong transmission systems to deliver the power. Wisconsin's largest power plant, the Pleasant Prairie plant in Kenosha County, has a capacity of approximately 1,200 megawatts (MW). Illinois, Michigan, Indiana, and Ohio have many larger plants, some more than twice as large. This is significant because when generation is concentrated in very large plants, an extensive high-voltage transmission system is necessary to allow for reliable system operation.

Maps such as Figure 2-2 contain information that can facilitate understanding of weaknesses in Wisconsin's transmission system. However, the relative size of Wisconsin's EHV network and number of connections to other states do not, by themselves, provide a sound basis for assessing the adequacy of Wisconsin's transmission system. Many other factors are important in determining how well a given transmission network fulfills the task of facilitating delivery of electricity to customers, and any assessment of system adequacy must focus on the question of how well the transmission system performs this function.

Figure 2-2 Extra-high-voltage (EHV) transmission system in Wisconsin and surrounding states



The continuous heavy line in Minnesota depicts a 500 kV line; in Illinois, Indiana, and Michigan this line type depicts 765 kV lines.

In large measure, the effectiveness with which the transmission network facilitates delivery of electricity to customers can be expressed in terms of the system's ability to provide transmission transfer capability from adjacent regions. For this reason, transmission transfer capability is a primary focus of the discussion of need in this EIS, and in the analysis found in the application for the proposed project. The engineering analyses discussed in this EIS, many of which are also cited in the application, focus on transmission transfer capability into a sub-region of MAIN known as the Wisconsin-Upper Michigan System (WUMS), which includes both eastern Wisconsin and the adjacent part of Michigan's Upper Peninsula. Accordingly, references to eastern Wisconsin in the context of these studies should be understood to include the adjacent region of the Upper Peninsula.

Recent history of reliability and electricity shortfalls

Concerns about the adequacy of Wisconsin's electric power system have grown with increasing electricity demand, and have intensified in the last few years. In the spring of 1997, all three of Wisconsin's nuclear generating units (about 15 percent of eastern Wisconsin's generating capacity) were out of service. The prospect of their return by summer, the season of peak electricity use, was uncertain. This threatened the ability of Wisconsin utilities to reliably serve demand and left them unusually dependent on power imports. Several nuclear power plant outages in Illinois further squeezed supplies.

While Wisconsin's nuclear power plants were running once again by the summer of 1998, significant outages continued in Illinois. As a consequence, power supplies were again tight as many regional utilities provided assistance to struggling Illinois utilities.

Entering the summer of 1999, the region's capacity picture appeared favorable, with nuclear plants on line in Wisconsin and Illinois. Still, power supplies were very restricted during peak demand periods in late July, as hot, humid weather throughout the region drove electricity demand to record levels.

In the summer of 2000, relatively cool temperatures and generation additions have allowed the Wisconsin utilities to meet their customer demands without serious difficulty. Through August 31, 2000, the Milwaukee area experienced no days with a high temperature above 90 degrees. The Madison area experienced one such day on August 31, 2000 when the high temperature reached 91 degrees. On August 31, 2000, the PSCW Electric Reliability web page was set to medium risk level including a medium probability of service curtailments of commercial and industrial interruptible loads.[5]

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[5] The Public Service Commission of Wisconsin internet website has links (http://www.psc.state.wi.us/elecrel/risk/vl.asp) to information about Wisconsin's electric reliability status. This web page contains the current state of electric reliability based on information from the state's electric utilities. When the system conditions warrant a change in status, this page will be updated to reflect that change. Typically, electric loads are lower on weekends and the risk of electric service interruptions will be less than during the week; therefore, changes to the status will generally not be made on weekends.

In order to quantitatively highlight the nature of the 1997 to 1999 reliability problem it is necessary to examine the operating reserves that the state's utilities had during summer peak demand conditions. Operating reserves refer to the megawatts of capacity remaining after a utility meets its net peak electric demand requirements. Operating reserves are often expressed as a percentage of net peak demand. An operating reserve margin above 10 percent reflects a healthy surplus of generating capacity on a summer peak day, while an operating reserve margin below 5 percent indicates a system in stress. For instance, the California independent system operator considers an operating reserve below 5 percent of peak demand reason for it to issue an electric reliability alert to the public. Table 2-1 contains operating reserve information for the period 1995 to 1999 in Wisconsin. Data in Table 2-1 are from the draft Strategic Energy Assessment (SEA) prepared by the Commission in June 2000.

Table 2-1 Peak day operating reserves as a percent of peak electric demand in Wisconsin

	1995	1996	1997	1998	1999
Statewide Utilities	6.6%	7.3%	7.0%	13.6%	10.0%
Eastern Wisconsin Utilities	5.1%	5.4%	4.1%	11.8%	8.7%

Source: draft Strategic Energy Assessment, June 2000.

Table 2-1 shows that operating reserves have never fallen below 5 percent at the statewide level during the period 1995 to 1999. This, however, is not true for particular sub-regions or utilities. The Eastern Wisconsin Utilities (EWU) have together on several occasions come close to the 5 percent threshold, and in one year, 1997, the EWU actually fell below the critical 5 percent operating reserves point.

In addition to these serious problems with regional generation experienced during recent years, problems with the transmission system began to emerge. Several factors contributed to these problems. First, generation outages in Wisconsin and nearby regions led to an increased need to move power into and through Wisconsin. In addition, some power plant outages had the effect of significantly reducing the ability of the transmission system to transfer power. This can occur, for example, when a power plant is needed not just to generate electricity but also to support the voltage on a transmission line. Since heavy power flows tend to reduce voltages, the absence of such voltage support may reduce the amount of power that is allowed to flow over a line.

Even as these problems shed light on weaknesses in the transmission system, the demand for power transfers across the system has been increasing. Driven by changes in federal regulation, the wholesale electricity market has greatly expanded since 1996, with significant accompanying growth in power transfers over long distances. The availability and low cost of electricity in the MAPP region frequently result in heavy flows of power from the west into and through Wisconsin. As the wholesale power market continues to expand, the demand to transfer power across this interface (between western and eastern Wisconsin) is likely to remain high.

Power transfer across this interface now can regularly reach the level at which the power system is at risk of experiencing line overloads or other problems. When this happens, system operators must curtail transactions to reduce the risk of damage or instability in the power system. Because power transfers can spread out over many separate transmission lines, such curtailments can have far-ranging effects, halting transactions hundreds of miles away from the endangered line. Not just Wisconsin, but the entire region may be affected by limits on Wisconsin transmission facilities.

These prevailing power flows from the west mean that, in the immediate future, the most pressing limitations on power import into eastern Wisconsin, as well as limits on flows through Wisconsin, are likely to occur between eastern and western Wisconsin, rather than between Wisconsin and Illinois. This situation is the reason utilities have now proposed a new line to the west rather than improvements to the south.

Most Wisconsin customers have not faced curtailments due to these problems so far, although very tight power supplies in recent summers meant utilities occasionally had to resort to public appeals for reduced electricity use. The only customers who have been forced to reduce consumption are those who have a special agreement with their utilities to reduce electricity use when so instructed by the utilities in exchange for financial incentives. These are primarily large industrial and commercial customers with so-called "interruptible" service. Some utilities also have installed remote control shut-off devices on residential air conditioners. Participants in these "direct load control" programs also receive financial incentives. Such arrangements free utilities of the obligation to meet the full electricity demand of these customers on high-demand days, reducing costs for all customers.

Interruption of service to interruptible and direct-load-control customers does not, by itself, indicate a reliability problem, since these programs are voluntary. Still, it can be quite disruptive to customers to be forced to curtail electricity use for several days in succession, as has happened. Wisconsin utilities are moving toward increasing the market orientation of such programs and allowing customers to choose their level of consumption on a day-to-day basis. At least for large customers, arrangements in which they face time-varying prices for all or a portion of their electricity service, and choose their electricity consumption, based on these prices, could still yield significant demand reduction. With market electricity prices occasionally reaching one hundred times the cost of production, changing electricity prices could provide a powerful incentive to change consumption patterns, particularly if customers can learn to increase their flexibility. Moreover, customers should be less dissatisfied if they have greater ability to choose their level of consumption, even if prices are high.

The experience of the summer of 1997 had significant repercussions in the following months. In the fall of 1997, the PSCW directed three eastern Wisconsin utilities to solicit additional capacity resources. This has led to two new power plants, which began operation before summer of 2000, and a third plant that is expected to be operational before summer 2001.

In a separate action, the Legislature passed 1997 Wis. Act 204. This law allowed non-utility "merchant" power plants to be built in Wisconsin. Merchant plants generate electricity, not with the intent of meeting the demands of particular utility customers, but to sell into the wholesale power market. The PSCW is currently reviewing one merchant plant application, and developers are considering a number of additional projects.

In addition, 1997 Wisconsin Act 204 required the PSCW to conduct a study aimed at relieving constraints to power transfers in Wisconsin. Utility engineers participated in this study, which is described in a PSCW report to the Wisconsin Legislature completed in September 1998.[6] The utilities followed that study with additional analysis. This work culminated, in June 1999, in a recommendation by the Wisconsin Reliability Assessment Organization (WRAO)[7] to build the Arrowhead-Weston Transmission Project.

Reliability

Population and employment growth translate into electricity use increases and problems

Increased transmission transfer capability from the north or west, increased electrical generation, or both are needed partly because of expected growth in the use of electricity in Wisconsin, as well as strong growth during the 1990s. Increases in electricity use are related to increases in population, employment, and use per customer (residential, commercial, or industrial). When customer electricity demands increase beyond a certain amount, the existing statewide transmission system may not be able to maintain adequate voltage or avoid facility overloads during contingency conditions. Consequently, customers throughout the state could face the risk of low voltage or service interruptions (controlled, rolling blackouts). If a service interruption occurs, it could last for minutes or hours.

Table 2-2 shows historical and forecast population and employment statistics covering the 1970 to 2007 time frame for counties in the EWU and in Wisconsin as a whole. Figure 2-3 shows a map of the EWU and Western Wisconsin Utilities (WWU) counties in Wisconsin. The time frame in Table 2-2 begins in 1970 in order to reflect the population and employment situation after the completion of the King to North Appleton 345 kV

[6] "Report to the Wisconsin Legislature on the Regional Electric Transmission System," PSCW, September 1, 1998. http://www.psc.state.wi.us/writings/papers/energy/elecrel/transsys.htm.

[7] The WRAO utility participants are WP&L; Dairyland Power Cooperative (DPC); Municipal Electric Utilities of Wisconsin (MEUW); MGE; MP; NSP; WEPCO; Wisconsin Public Power, Inc., (WPPI); WPSC; and the Wisconsin Federation of Cooperatives. The staff of the PSCW participates regularly in an ex officio capacity.

transmission line, the last major line connecting eastern Wisconsin to Minnesota and the MAPP reliability region. The application used the year 2007 because it reflects the ten-year forecast period from Advance Plan 8 (AP-8)[8] and the study period chosen by the WRAO when it investigated transmission needs in the state.

Table 2-2 shows that the EWU region constitutes over 80 percent of Wisconsin's population and employment. This table also indicates that population has grown and is expected to continue to grow between 0.56 and 0.87 percent per year in both the WWU and the EWU regions. During 1990 to 1997, Wisconsin population increased more than 299,000, growing on average 0.85 percent per year, according to the U.S. Bureau of Economic Analysis. Recent data from the DOA for the period 1990 to 1999 suggest similar population growth patterns. Such population growth is expected to slightly moderate during the 1997 to 2007 time frame, with an expected annual population growth of 0.75 percent. Nonetheless, between 1997 and 2007, the state's population could grow by an additional 400,000 persons.

Table 2-2 also indicates that total non-farm employment has grown and is expected to continue to grow between 1.39 and 3.19 percent per year in both Wisconsin and the EWU. During 1990 to 1997, Wisconsin non-farm employment increased more than 340,000, on average growing 2.11 percent per year, according to data from the state's unemployment compensation system. The rate of employment growth in the EWU area is only slightly slower at 1.99 percent per year. Recent data from the Wisconsin Department of Workforce Development (DWD) for the period 1990 to 1999 suggests similar total employment growth patterns for Wisconsin and the EWU region. Due to slower growth in the eligible labor force, however, these EWU and Wisconsin employment trends are expected to moderate somewhat during the 1997 to 2007 time frame in which non-farm employment growth in Wisconsin could average 1.46 percent per year, roughly creating 390,000 new jobs. In comparison, total employment in the WWU area is expected to grow about 1.85 percent per year.

[8] AP-8 was the most recent installation of the statewide generation and transmission planning process that was previously required by state law. The Commission's AP-8 order was issued in January 1999. This process has now been discontinued, supplanted by the SEA.

Table 2-2 Population and employment changes 1970 to 2007

Population (US Bureau of Economic Analysis)					**Annual Average Growth Rates**				
								AP-8	Forecast
	1970	1980	1990	1997	70-97	80-97	90-97	97-07	2007
EWU	3,724,374	3,917,806	4,085,075	4,333,674	0.56%	0.60%	0.85%	0.75%	4,669,891
WI	4,425,944	4,712,045	4,902,068	5,201,226	0.60%	0.58%	0.85%	0.75%	5,604,750
	EWU population change 90-97			248,599					
	WWU population change 90-97			50,559					
	WI population change 90-97			299,158					
Population (Wisconsin Department of Administration)(DOA)					**Annual Average Growth Rates**				
								AP-8	
			1990	1999			90-99	97-07	
		EWU	4,075,888	4,405,050			0.87%	0.75%	
		WWU	815,881	869,777			0.71%	0.75%	
		WI	4,891,769	5,274,827			0.84%	0.75%	
Non-farm Employment (Wisconsin March Unemployment Compensation system)					**Annual Average Growth Rates**				
								AP-8	Forecast
	1970	1980	1990	1997	70-97	80-97	90-97	97-07	2007
EWU	952,316	1,590,681	1,858,847	2,134,375	3.03%	1.74%	1.99%	1.39%	2,450,315
WI	1,072,852	1,882,772	2,166,004	2,506,269	3.19%	1.70%	2.11%	1.46%	2,897,185
	EWU employment change 90-97			275,528					
	WI employment change 90-97			340,265					
Total Employment (WI Department of Workforce Development Local Area Unemployment Statistics system) (DWD LAUS)					**Annual Average Growth Rates**				
								AP-8	
			1990	1999			90-99	97-07	
		EWU	2,025,898	2,430,669			2.04%	1.39%	
		WWU	417,974	445,894			0.72%	1.85%	
		WI	2,443,872	2,876,563			1.83%	1.46%	

Sources: U.S. Bureau of Economic Analysis, series CA1-3 and CA34; Bureau of Labor Market Information, Wisconsin Department of Workforce Development, March Unemployment Compensation reports and Local Area Unemployment statistics (LAUS); AP-8, Phase I, PSCW, November 20, 1997; and DOA.

Figure 2-3 Map of EWU and WWU Counties

Increases in employment and population generally cause increases in electric demand. Table 2-3 presents the growth in yearly peak electric demand measured in MW for the period 1970 to 1998.[9] This table generally corresponds to those presented for employment and population changes. During the 1990s electric demand has been growing 1.99 percent per year in eastern Wisconsin and 2.74 percent per year in the whole state. This is displayed in Figure 2-4. Such growth rates closely parallel those observed for non-farm employment. During the 1990 to 1998 period electric demand grew 1,400 MW in eastern Wisconsin, roughly 175 MW per year. At the statewide level, electric demand grew 2,358 MW, or about 294 MW per year. In AP-8, electric demand was forecasted to grow 2 percent per year for the 1997 to 2007 time frame. This means that peak electric demand could grow about 2,365 MW between 1998 and 2007, or 263 MW per year on average in the state of Wisconsin.

This increase in electric demand can be met by a combination of new electric generating facilities, an expansion of the ability to purchase or import electric power from other states and regions (by increasing transmission system transfer capability), and by energy-efficiency efforts. Not accommodating this expected amount of new electric demand would pose unacceptable reliability risks.

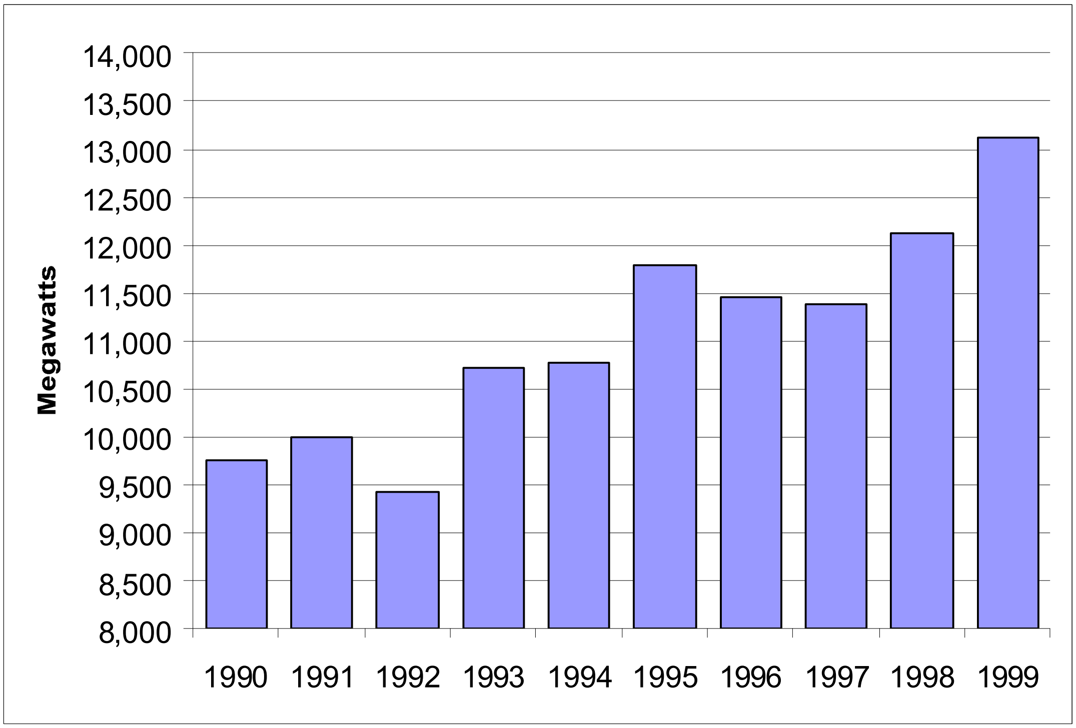
Table 2-3 Electric demand growth 1970 to 2007

Coincident Peak Demand (MW)					Annual Average Growth Rates				
								AP-8	Forecast
Year	1970	1980	1990	1998	1970-98	1980-98	1990-98	1997-2007	2007
EWU	4,125	6,019	8,184	9,584	3.06%	2.62%	1.99%	2.00%	11,454
WI	4,885	7,368	9,764	12,122	3.30%	2.80%	2.74%	2.00%	14,487
EWU peak demand change 90-98	1,400								
WI peak demand change 90-98	2,358								

Sources: Commission staff and Advance Plan 8, Phase I, Public Service Commission of Wisconsin, November 20, 1997.

[9] Demand data used here end in 1998 so as to remain consistent with the coincident peak demand data series established for the Advance Plan and subsequently used to develop the Commission's AP-8 forecast. 1999 statewide coincident peak demand data is no longer available due to the elimination of the Advance Plan in favor of the new SEA, which uses non-coincident data. Trends in the SEA non-coincident peak demand data parallel those in the Advance Plan data sets, however. For the period 1995 to 1999, statewide non-coincident electric peak demand grew 2.90 percent per year.

Figure 2-4 Wisconsin peak demand 1990 to 1999



Electricity supply adequacy

Background

The previous section of this chapter notes that population and electricity demand are continuing to grow in Wisconsin. This suggests that one element of need for transmission improvements – the need to increase transmission transfer capability so as to improve Wisconsin's access to needed electricity supplies – may also be growing. Analytical methods allow this need for additional transfer capability to be quantified. This section describes such an analysis of the Wisconsin power system and explores the implications of its results.

Utilities plan reinforcement of the electric power system to ensure that electric service to customers will be reliable. A reliable system is one that is able to deliver customers' electricity demand while satisfying a range of system security criteria (related to the ability of the system to remain stable when subjected to disturbances, and to avoid blackouts).

Some combination of generation and transmission is usually required in order to provide reliable service to customers. Because generating plants and transmission lines can fail unexpectedly, the system is designed with some redundancy so that power can continue to flow where it is needed even after such an occurrence. An unexpected failure of generation plants or transmission lines is known as a "contingency."

Nonetheless, no power system can immunize itself completely against the possibility of a major, unplanned outage (or multiple, simultaneous outages) in which demand exceeds supply. If this should occur, utilities would have to shut off power to some customers. This is known as shedding load, and could take the form of "rolling blackouts" in which different parts of the utility's service territory take turns having their power shut off for one to three hours.

Beyond rolling blackouts, it is also possible for a disturbance at a time of severe system stress to lead to uncontrolled system failure and a blackout over a large area. This would be a much more severe event than the imposition of rolling blackouts intended to reduce demand. A large area could be affected and system restoration could take hours or even days. While such an event is always a risk, it is the principal goal of system operation to avoid such an occurrence.

Rapid change in the electricity market and increasing flows on the system in the last few years have at times made it difficult for operators to control power flows that create stress on their electric systems. This, together with inadequate anticipation of system behavior at high transfer levels and the inability of system operators to respond properly to disturbances, has led to recent disturbances on Wisconsin's power system. These disturbances have threatened widespread blackouts. In principle, however, it should be possible to correct the causes of these events so as to keep the risk of an uncontrolled blackout at a known and acceptably low level. If necessary, the risk of such a disturbance could be managed by shedding load. Accordingly, the consequence of power system inadequacy should be seen primarily as the risk of experiencing periodic controlled, rolling blackouts rather than uncontrolled, large-scale blackouts.

Loss-of-load expectation (LOLE) analysis

Utility engineers measure reliability by calculating the likelihood of a power shortfall that would force the use of rolling blackouts. They use a unit of measure called a loss-of-load expectation (LOLE). This is the fraction of time that electricity demand is likely to exceed available sources of power in a given system. By taking into account such factors as the expected generating unit outage rates, scheduled maintenance outages, and electricity demand, engineers can calculate the LOLE of a given power system. This, in turn, allows power system planners to determine how much electricity supply, in the form of power plants within the region or transmission connections to other regions, they must provide in order to meet a given LOLE criterion. Reductions in demand could have much the same effect as increases in supply.

The smaller the LOLE figure, the more reliable the system. In North America, utilities have generally adopted the standard that LOLE should not exceed 0.1 day per year. This is equivalent to saying that a loss-of-load event, in which one or more utilities would have to implement rolling blackouts, would be expected to occur only one day every ten years.

It is important to recognize that the LOLE measure only considers electricity shortfalls on the bulk, high-voltage power system. Most customers experience outages more frequently than once a decade, and these outages are usually caused by equipment failure or weather-related damage to the low-voltage distribution system. In addition, as noted earlier, some customers in Wisconsin have agreements with their utility that require them to shut off equipment when asked to do so by the utility, in exchange for financial incentives. Neither of these outage types is reflected in the LOLE analysis.

The WRAO retained a consultant in 1999 to perform a LOLE analysis as the primary element of an assessment of the need for transmission system import capability into eastern Wisconsin. Subsequently, at the request of Commission staff, the applicants had this consultant repeat the analysis, with certain assumptions modified, for inclusion in the application for the proposed project. The results of this second analysis are presented in Tables 2-4 and 2-5.[10]

The tables show two distinct cases. Table 2-4 assumes that new generation is added each year in eastern Wisconsin so as to maintain a generation reserve margin of 18 percent. In other words, it assumes that the total generation capacity within eastern Wisconsin exceeds the yearly peak demand by 18 percent. This amounts to 1,560 MW of new electric generation through 2007.

In contrast, Table 2-5 represents the situation in which no new generation is added within eastern Wisconsin through 2007, beyond that already approved by the PSCW. All new power requirements are assumed to be met through purchases from outside generation that are brought into Wisconsin using transmission transfer capability.

The values of required transmission transfer capability shown in each table (row g) are derived by adding capacity purchases from outside eastern Wisconsin to the model until the calculated LOLE is reduced to the criterion value of 0.1 day per year. In this analysis, transmission transfer capability is modeled as a perfectly reliable source of power.

The two cases described in the tables bracket the likely range of possibilities regarding generation expansion in eastern Wisconsin. Thus, this LOLE analysis indicates that the need for transmission transfer capability into eastern Wisconsin lies somewhere between 730 MW (Table 2-4) and 2,200 MW (Table 2-5) depending on the amount of new generation that is actually installed in eastern Wisconsin.

These analyses assumes that 975 MW of new generation capacity will be installed by June 2000. This number is incorrect, though, because it includes 450 MW of capacity from

[10] The assumptions underlying the original LOLE analysis conducted by the utilities' consultant (Mr. Ron Harsevoort) are detailed in Attachment C to the June 1999 WRAO Report, which can be downloaded (in the document entitled "Transmission Capacity Requirements") from http://www.maininc.org/committees/wire~1.htm. At Commission staff's request, this analysis was repeated with different assumptions regarding availability of capacity purchases. These issues are elaborated in the discussion of sensitivity of LOLE results to changed assumptions that appears a few pages ahead.

the RockGen plant. Construction of this plant has been delayed, and is now not expected to be on line before summer 2001. Thus the assumptions in the table are considered valid for 2001 and beyond.

Present-day firm transmission transfer capability into eastern Wisconsin is approximately 1,000 MW. Accordingly, these results suggest that, if no new generation is built by 2007, significant improvements in transmission transfer capability would be required to provide eastern Wisconsin with adequate access to power supplies. In contrast, if a significant amount of new generation is installed, these types of improvements may not be required to ensure that adequate supply can be accessed. Overall reliability would still need to be considered.

The proposed line, together with a number of much more modest improvements in the transmission system[11], is expected to increase transmission transfer capability into eastern Wisconsin to at least 3,000 MW. Accordingly, this project would be sufficient to meet the transfer capability needs specified in the Commission's 1998 Report to the Wisconsin Legislature that would arise if no new generation is constructed.

Table 2-4 LOLE analysis – assuming generation added to provide Eastern Wisconsin with 18 percent generation reserve margin

		2000	2001	2002	2003	2004	2005	2006	2007
a	Peak demand net of interruptible loads (MW)	10,374	10,582	10,757	10,953	11,161	11,387	11,573	11,754
b	Generation capacity as of January 1 (MW)	11,339	12,314	12,484	12,694	12,924	13,174	13,434	13,654
c	New generation on line as of June 1 (MW)	975	----	----	----	----	----	----	----
d	Generation reserve margin before capacity additions	18.7%	16.4%	16.1%	15.9%	15.8%	15.7%	16.1%	16.2%
e	Generation added to meet 18% reserve margin (MW)	----	170	210	230	250	260	220	220
f	LOLE before capacity purchases (days/year)	3.77	1.20	1.38	1.38	1.17	1.10	1.00	0.92
g	Capacity purchases required to meet 0.1 day/year LOLE (MW)	1,040	750	820	860	780	770	750	730
h	Total capacity resources (generation + purchases) (MW)	13,354	13,234	13,514	13,784	13,954	14,204	14,404	14,604
i	Reserve margin required to meet 0.1 day/year LOLE	28.7%	25.1%	25.6%	25.8%	25.0%	24.7%	24.5%	24.2%
j	Cumulative generation capacity added beyond that already approved (MW)	0	170	380	610	860	1,120	1,340	1,560

[11] These additional projects are detailed in Table 3-8.

Table 2-5 LOLE analysis – assuming no additional Eastern Wisconsin generation beyond that already approved by PSCW

		2000	2001	2002	2003	2004	2005	2006	2007
a	Peak demand net of interruptible loads (MW)	10,374	10,582	10,757	10,953	11,161	11,387	11,573	11,754
b	Generation capacity as of January 1 (MW)	11,339	12,314	12,314	12,314	12,314	12,314	12,314	12,314
c	New generation on line as of June 1 (MW)	975	----	----	----	----	----	----	----
d	Generation reserve margin before capacity additions	18.7%	16.4%	14.5%	12.4%	10.3%	8.1%	6.4%	4.8%
f	LOLE before capacity purchases (days/year)	3.77	1.74	3.20	5.56	7.73	11.85	16.34	21.99
g	Capacity purchases required to meet 0.1 day/year LOLE (MW)	1,040	890	1,150	1,430	1,570	1,810	2,000	2,200
h	Total capacity resources (generation + purchases) (MW)	13,354	13,204	13,464	13,744	13,884	14,124	14,314	14,514
i	Reserve margin required to meet 0.1 day/year LOLE	28.7%	24.8%	25.2%	25.5%	24.4%	24.0%	23.7%	23.5%

Reserve margin implications in LOLE analysis

The use of 18 percent as the target generation reserve margin in the Table 2-4 analysis stems from the fact that the PSCW has, in recent years, required Wisconsin utilities to arrange for a reserve margin of at least 18 percent in their supply plans. Utilities have typically met this reserve margin requirement by relying on imports as well as on local generation, but the assumption in this LOLE analysis is that the reserve margin requirement is met entirely through generation within eastern Wisconsin.

By itself, an 18 percent reserve margin is not sufficient to provide adequate reliability of electric service. This is shown by the values in row i of Table 2-4 and 2-5, which show that overall EWU reserve margins between 23 percent and 29 percent are necessary to achieve the target LOLE level. Utilities can satisfy this reliability criterion by arranging, by the beginning of the peak season, for supplies that will provide a reserve margin of 18 percent. They would then have to rely on the transmission system for access to additional generation capacity, if electricity demand and unit outages render this 18 percent insufficient.

As the geographic size and diversity of a power system decreases, the reserve margin required to ensure reliable service increases. Thus, while each utility individually may require access to 130 percent or more of its peak demand in order to provide reliable service, adequate transmission connections between utilities allow sharing of reserves, such that the total amount of generation required across a large region may only be 118 percent of regional peak demand. As a consequence, if each utility in this region independently maintains a reserve margin of 18 percent then there will be enough extra power to ensure that the LOLE criterion can be met for all utilities, provided that transmission interconnections between the utilities are adequate.

In contrast, if the ability of the transmission system to transfer power between utility service areas is inadequate, or if the utilities use much of the available transfer capability just to achieve an 18 percent reserve margin, having an 18 percent reserve margin will not, by itself, ensure that the LOLE criterion can be met. Accordingly, although the Wisconsin utilities report planning reserve margins collectively in excess of 18 percent through 2002[12], this does not necessarily ensure that they can achieve a 0.1 day per year LOLE, since at present they rely heavily on Wisconsin's transmission interconnections to achieve their reserve margin.

A final point of interest that emerges from the two tables is that they show, in row i, that the overall reserve margin requirement appears to decline in future years. This is largely a consequence of the relatively high reliability of the new generating units assumed in the analysis, and of their small single-unit capacity ratings, relative to the overall generation inventory in the state. A large number of small generating units provides more diversity and, in general, better overall reliability than a small number of large units.

Sensitivity of LOLE analysis results to changed assumptions

The conclusions described above are based on a particular LOLE analysis, in which transmission transfer capability was assumed to be equivalent to perfectly reliable generation capacity. In reality, transmission transfer capability can vary significantly depending on outages and the pattern of power flow across the system. The transmission system generally has a number of lines out of service at any one time, due to both scheduled and unscheduled outages, and this occasionally leads to a significant reduction in the ability of the system to transfer power. Similarly, unusual patterns of power flow, caused by variations in regional demand and generator availability, can affect the ability of the system to import power. For these reasons, this LOLE analysis probably understates the transmission transfer capability required to meet a given LOLE target level.

In addition, the LOLE analysis described above assumes excess generation capacity available for purchase in other regions. In reality, it may not be possible to use all of the transmission transfer capability in an emergency because there simply may not be power to purchase.

By modifying the assumption that transmission transfer capability is equivalent to perfectly reliable generation, it is possible to assess the error that this assumption may introduce. The original WRAO LOLE analysis conducted, in early 1999, differed from the one reported in Tables 2-4 and 2-5 only in its treatment of transmission transfer capability. Rather than assuming that transfer capability is 100 percent available, which is the assumption underlying Tables 2-4 and 2-5, this earlier analysis modeled transfer capability as having reliability characteristics comparable to generating units. In addition, only half of this capacity was assumed to be available in the spring and fall; all this capacity was assumed to be available during the summer and winter.

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[12] See, for example, pp. 6-7 of the draft PSCW SEA, Draft Report (June 2000). This report is available in electronic form at http://www.psc.state.wi.us/cases/sea/index.htm. See also the MAIN Summer 2000 Load and Resource Audit Report at http://www.maininc.org/bod/2000/SATF2000r.pdf.

These may or may not be appropriate assumptions. Regardless, they provide a good opportunity to examine the sensitivity of LOLE analysis results to the availability of transmission transfer capability. The lower the reliability assumed for transmission transfer capability, the more transfer capability is needed to provide eastern Wisconsin with adequate access to power supplies. Table 2-6, which shows all the LOLE results discussed so far, demonstrates this effect.

Table 2-6 Required transmission transfer capability in 2007 as determined by LOLE analysis with varying assumptions

LOLE Analysis Results -Requirements for Import Capability Into Eastern Wisconsin Year 2007		**Assumption Regarding New Generation**	
		Add 1,560 MW to Maintain 18% Reserve Margin	None Beyond That Already Approved
Assumptions regarding availability of transmission transfer capability	Perfectly available	730 MW	2200 MW
	Comparable to generation; also, reduced by half during spring and fall	910 MW	3410 MW

Table 2-6 shows that, if significant generation additions occur in eastern Wisconsin, the amount of transmission transfer capability required is not greatly affected by the availability level assumed for a given amount of transfer capability. In contrast, if no new generation is added, the amount of required transmission transfer capability is much greater and is also highly dependent on the availability of that transfer capability. More generally, Table 2-6 supports the analysis results discussed earlier: with sufficient generation additions, no increase in transfer capability is required to provide eastern Wisconsin with adequate access to electricity supply resources through 2007; with no new generation, significant transmission improvements would likely be required.

Expected new generation construction

The previous section shows that the need for transmission improvements is influenced by the amount of new generation that is built in eastern Wisconsin in the near future. While the precise schedule of new plant construction is unknown, some information is available now. Badger Generating Company, LLC, a non-utility power plant developer, filed an application with the PSCW in December 1999 to build and operate a large power plant in southeastern Wisconsin. If the Commission approves this project, it could be operating at a site in Racine County or Kenosha County by 2003. As proposed, this plant would have a capacity of approximately 1,050 MW.

Since this would be a merchant power plant, it is not yet known whether the electricity it would generate would be sold to Wisconsin utilities. An out-of-state sale by a generator within Wisconsin, however, would effectively increase the import capability of Wisconsin's transmission system during times that the plant is operating. Thus from the perspective of

LOLE analysis, the Badger Generating plant would have a positive impact on reliability in southeastern Wisconsin, even if the power is sold to an out-of state buyer.

As for other generation developments, WP&L issued a request for proposals (RFP) on April 25, 2000, to obtain approximately 500 MW of additional electric capacity. Responses to the RFP may result in proposals to construct new generation in Wisconsin, or may include proposals to sell WP&L capacity from existing or previously planned generation. If WP&L accepts a proposal that includes the construction of new generation, the Commission expects that a CPCN application will be submitted to the Commission later this year or early next. It is WP&L's goal to have 300 MW of additional electric capacity on line by 2002 and the remainder available the following year.

WP&L is also under contract with RockGen Energy for the construction of 450 MW of combustion turbine (CT) capacity in the town of Christiana in Dane County. This facility, called the RockGen Energy Center, is presently the subject of litigation, which held up the start of construction. Regardless of the outcome of this litigation, operation is expected to occur by summer 2001. The generation capacity that the RockGen plant would provide, however, was assumed to be installed by 2000 in the LOLE analysis. Accordingly, this capacity does not count toward the 1,560 MW of capacity that Table 2-4 identifies as required to ensure adequate electricity supply (in the absence of transmission improvements) by 2007.

Additional potential new generation developments are discussed in Chapter 4.

In conclusion, while the proposed Badger Generating facility is but one example of how the newly deregulated wholesale power market is working in Wisconsin, it is not unreasonable to expect that additional merchant power plants will be proposed and constructed in the next few years in Wisconsin. Such new generating plants would also affect the import capability of Wisconsin's transmission system. To what extent is unknown. How a deregulated wholesale power market could affect the need for the Arrowhead-Weston project is discussed further in Chapter 4.

Influence of nuclear generator outage rates on LOLE analysis

Any LOLE analysis is based on a range of assumptions, including future electricity demand and the likelihood of generating units experiencing unplanned outages. The likelihood of such outages, which is expressed in a measure known as forced-outage rate, warrants particular scrutiny. The accuracy of the LOLE analysis depends on the accuracy of these forced-outage rate assumptions. Nationwide power plant operating experience generally provides a firm basis for forced-outage rate assumptions. Nuclear generating unit forced-outage rates warrant extra examination, however, since these complex generators can be forced out of service, by technical or regulatory problems, for months at a time.

The LOLE analyses described previously used forced-outage rate assumptions for Wisconsin's three nuclear generating units that were based on the actual operating experience for those units during the 1994-1998 period. This was probably a conservative assumption, since these units experienced a particularly large number of outage days during this period. Accordingly, this aspect of nuclear plant reliability probably does not suggest the need to increase transmission transfer capability levels beyond those identified in the LOLE analyses.

One additional nuclear-unit forced-outage rate consideration is appropriate, however. Specifically, it may be that unit outages are not independent events, as assumed in the LOLE analysis, but that multiple outages may stem, at least in part, from a single common cause. If unit outages are positively correlated, then the LOLE analysis—which assumes outages are independent of one another—will tend to overestimate the reliability of the system.

It is generally safe to assume that generating unit outages are independent events. The situation is more complex, however, in the case of nuclear plants that have much common technology, strict safety standards, and that may be forced to shut down—or to remain shut down—by the federal Nuclear Regulatory Commission (NRC), which has oversight authority. To evaluate the possibility that the forced-outage rate for Wisconsin nuclear units could result from a common cause rather than independent events, a review of the recent outages of the nuclear units in Wisconsin, Illinois, Iowa and Minnesota is necessary. For this EIS, the review of units outside Wisconsin was general in nature and was more detailed for the Kewaunee and Point Beach nuclear units. As part of this EIS, current NRC inspection methodologies were reviewed to attempt to determine the impact NRC regulation may have on forced-outage rates of nuclear units.

During the late 1990s nuclear power plants in the upper Midwest experienced several unplanned outages. Nuclear power plants are generally large, producing between 500 and 2,000 MW of electricity. When an unplanned outage of a large nuclear power plant occurs, the host utility must obtain replacement electric power from the wholesale power market. This involves transferring significant amounts of power over the transmission grid.

This requirement to move large blocks of electric power can lead to congestion on the transmission system as well as significant electric generating power plant redispatch throughout the region. Moreover, the nuclear plant outage itself can affect the simultaneous import and export characteristics of the transmission system. One potential remedy to the increased usage, congestion, and change in import and export capabilities arising out of an unplanned large power plant outage is to have the transmission system properly scaled to handle such contingencies. As the probability of such unplanned large generating plant outages increases, there can be a corresponding need for increased transmission capability to handle potential congestion and increased electric power trade or traffic. In a way, increased transmission system transfer capability can act as insurance against a large-scale unplanned outage at a nuclear power electric generating station. Table 2-7 highlights those nuclear power plant outages occurring in Wisconsin, Minnesota, and northern Illinois since 1996.

These outages are graphically shown in Figure 2-5, in which the thickness of each bar is proportional to the rated generation capacity of the corresponding generator.

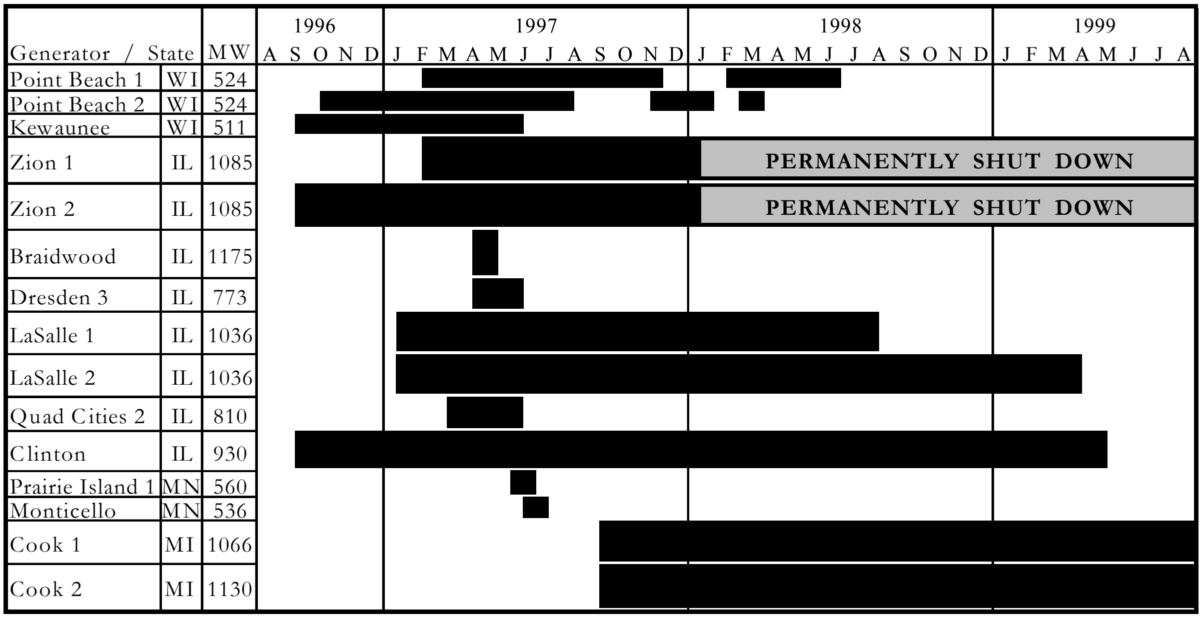
As shown in Figure 2-5, during the period of February 1997 through June 1997, all three nuclear units in Wisconsin were off-line. This represented a loss of over 1,500 MW. These nuclear plant outages, as well as those in Illinois, significantly reduced the power supply in Wisconsin during the spring and summer months of 1997 and 1998. There have been continuing effects into 1999 due to the shutdown of the Zion nuclear power plant facilities. The following discussion provides more detail on events occurring in Wisconsin.

Table 2-7 Nuclear power plant outages 1996 to 1999

Facility	Capacity	Outage
WE Point Beach Unit 1	524 MW	February 1997 to November 1997 and March 1998 to June 1998
WE Point Beach Unit 2	524 MW	November 1996 to July 1997 and December 1997 to January 1998
WPS Kewaunee	511 MW	October 1996 to May 1997
CE Zion Unit 1	1,085 MW	February 1997 to present, shut down permanently January 15, 1998
CE Zion Unit 2	1,085 MW	September 1996 to present, shut down permanently January 15, 1998
CE Braidwood Unit 1	1,175 MW	April 1997 to May 1997
CE Dresden Unit 3	73 MW	September 1996 to May 1999
ILP Clinton	930 MW	September 1996 to May 1999
CE La Salle Unit 1	1,036 MW	January 1997 to August 1998
CE La Salle Unit 2	1,036 MW	January 1997 to April 1999
CE Quad Cities Unit 2	810 MW	March 1997 to June 1997
NSP Prairie Isle Unit 1	560 MW	June 1997
NSP Monticello	536 MW	June 1997 to July 1997
AEPC DC Cook Unit 1	1,066 MW	September 1997 to present
AEPC DC Cook Unit 2	1,130 MW	September 1997 to present

Source: Commission staff; NRC web site. Generating capacity reflects the rated output of the main turbine generator.

Figure 2-5 Recent nuclear generating unit outage history for selected units



Source: Commission staff; NRC web site.

On October 5, 1996, Point Beach Unit 2 went off-line for a scheduled refueling outage. During this refueling outage, the unit's steam generators were replaced. In order to replace the steam generators the nuclear fuel core must be fully off-loaded. However, beginning in 1995, Point Beach did not have enough open space in the spent fuel pool to off-load a full core. To address this situation, Point Beach chose the VSC-24 dry storage cask as an additional spent fuel storage technology. On May 28, 1996, the welding of the lid onto the third VSC-24 cask ignited hydrogen gas in the cask. From May 30 through June 7, 1996, the NRC had an Augmented Inspection Team (AIT) at Point Beach to investigate the hydrogen burn. The results of this and other subsequent inspections resulted in the December 5, 1996, NRC request that WEPCO compile a list of issues needing resolution prior to the restart of Unit 2. WEPCO submitted a list of 81 restart issues to the NRC on December 12, 1996. Some of the restart items were common to systems used in both Unit 1 and Unit 2. Unit 2 resumed operation on August 17, 1997. Unit 2 came back off-line on November 11, 1997 for approximately three months. It was also off-line for three weeks in March 1998.

Point Beach Unit 1 came off-line on February 18, 1997 to address impeller problems on a component cooling water pump and bearing problems on a service water pump. Unit 1 returned to service on December 1, 1997. Unit 1 was taken off-line again on February 15, 1998, for a refueling outage. It was brought back on-line on June 30, 1998.

During the period of February 18 to December 1, 1997, WEPCO staff became aware that issues relating to a potential large break loss-of-coolant accident and to the auxiliary feedwater system (AFS) would also need to be addressed. The AFS issue prevented both units being operational at the same time until it was resolved. The plant modifications necessary to resolve the AFS issue were completed in January 1998.

The Kewaunee unit came off-line on September 20, 1996, for a scheduled refueling outage. During the refueling outage it was discovered that there were significant repairs needed to the steam generator tubes prior to restarting the unit. Kewaunee returned to service on June 12, 1997 and was at 94 percent power on June 29, 1997. Currently, the Kewaunee steam generators are scheduled to be replaced in the fall of 2001.

The lack of nuclear generation in Wisconsin during the spring and summer of 1997 resulted in the need to import large quantities of electricity. However, this was made difficult by the fact that in Illinois up to 8,000 MW of nuclear generation were off-line at times during this period. Further, during the periods of June and July 1997, between 500 and 1,100 MW of nuclear power were off-line in Minnesota.

Upon review, there does not appear to be a common root cause that resulted in all three Wisconsin nuclear units being unavailable during the spring and summer of 1997. The outages resulted from different causes. For Point Beach, the cause appears to have been operational performance and maintenance activities at a level that concerned the NRC. For Kewaunee, the cause was the material condition of the steam generators, not performance or maintenance issues.

Given the reasons for all three nuclear units in Wisconsin being off-line at the same time in 1997, it currently appears less likely that all three nuclear units will be off at the same time in the future. Once the steam generators are replaced at Kewaunee in 2001, all the nuclear units in the state will have had their original steam generators replaced. Based on the March 26, 1999, plant performance review issued for Point Beach, this plant has improved its operational performance and maintenance since 1996 and 1997. Further, the NRC is changing the way it reviews plant performance. Given the contents of the March 26, 1999, plant performance review issued for Kewaunee, it appears that the NRC is becoming more proactive in identifying operational performance and maintenance issues that are of concern. This should allow plant management more time to address such issues before they become significant problems.

This analysis indicates that, in the near future, outage rates of Wisconsin nuclear units are not likely to exceed the levels of 1994-1998. In addition, it appears that common-mode outages are not likely to have a significant impact on reliability. These results, in turn, suggest that no additional transfer capability, beyond the level identified in the previously discussed LOLE analyses, should be required to account for possible nuclear plant reliability problems.

Common-mode problems in non-nuclear units

Non-nuclear generating units can also experience outages or limitations on their output as a result of a common problem. For example, some coal-fired power plants may have common coal-handling equipment for multiple generating units at a single location. If the common coal-handling system experiences problems, it may prevent several units from operating at their full capacity. Severe weather can affect generating units over a larger area. For example, ice storms can coat outdoor coal piles, making it difficult to load enough coal to keep generating units operating at full capacity. Events like these are relatively infrequent, however, and their omission probably does not significantly affect the accuracy of LOLE analyses.

Hot, humid weather can also reduce the capability of generating units. Steam turbine generating units may be unable to operate at full capacity when extended hot weather leads to excessive temperatures in the rivers or lakes that provide condenser cooling water. Similarly, hot, humid air prevents combustion turbine generating units from operating at their full capacity.[13] Such forced unit deratings are particularly troublesome because hot, humid weather also tends to cause electricity demand to reach its peak levels. For example, some Wisconsin utilities reported such problems during late July 1999, during which time the state exceeded the previous electricity demand record by a large margin. This experience suggests that LOLE analyses may overstate reliability if it disregards the possibility of generator derates due to hot weather.

Age and condition of the transmission system

As noted previously, the age and condition of generation facilities can affect the reliability of the power system. Similarly, transmission facilities degrade with time and can suffer reduced reliability with increased age. While much of the existing 345 kV system, including the existing 345 kV connection between Minnesota and eastern Wisconsin (the King-North Appleton line), is approximately 30 years old, these lines are still in good condition. Nonetheless, some concerns may be appropriate to consider with respect to the existing transmission system. In particular, consideration should be given to the potential for extended outages of important existing 345 kV links, whether the outage is due to routine maintenance or unexpected damage. Given that the existing 345 kV connection has been heavily used in recent years, an extended outage of one part of this line could have a severe reliability impact on Wisconsin. This suggests the desirability of providing increased redundancy in Wisconsin's high-voltage transmission system.

Other transmission system problems

The earlier discussion of LOLE analysis focused on one possible reason for transmission improvements: the need for increased transmission transfer capability to provide adequate access to electricity supply as electricity demand in Wisconsin increases. There may be additional reasons for new transmission construction, however. For example, even at levels

[13] These unit derates are described in the eastern Wisconsin utilities' responses to the Commission's fall 1999 inquiry into the circumstances at the time of the 1999 summer peak.

of power transfer that the present-day Wisconsin system can sustain, there are notable deficiencies in the power system that point to the need for reinforcement.

Operating guides

The transmission system is generally designed with some redundancy. In particular, it is designed so that electrical demand can continue to be served even after any single transmission element (power line or transformer) is forced out of service. Adherence to this design principle significantly increases electric service reliability. Reliability is occasionally compromised in the present power system, however, because weaknesses in the existing system can force operators to remove from service lines that provide important redundancy benefits.

A typical example is as follows: The power system experiences heavy – but sustainable – levels of demand and power transfer. Storm damage or equipment failure forces removal of a key transmission line for an extended period. With this line out of service, the flow of power over the remaining system changes in a way that causes another line to become overloaded. If this overload were allowed to continue, circuit breakers would trip to remove part of the line from service and eliminate the overload. In order to prevent this from occurring, system operators (or automatic equipment, in some cases) remove part of this line from service (or possibly a different, connected line), eliminating the overload situation. Such a planned, controlled removal of a line from service is preferable to the uncontrolled action of protective circuit breakers because operators can select the line section to remove from service so as to maintain system security as much as possible.[14]

This is an example of an "operating guide," an established procedure that system operators may use to maintain the security of the system when it is threatened by overloads or other problems. Such operating guides may be effective in eliminating overloads; they also may have the negative effect of reducing the redundancy that secures reliable service to customers. Accordingly, a legitimate goal of those who plan development of the transmission system is to reduce the need to rely on those operating guides that may diminish reliability of electric service to customers.

In the present-day Wisconsin power system, a number of operating guides are required to allow continued transfers of power into and through Wisconsin when sections of the existing King-North Appleton 345 kV line are forced out of service. When these operating guides are invoked, they leave some customers vulnerable to loss of service in the event of a second key outage.

The need for such operating guides can sometimes be eliminated by reinforcing the line that is susceptible to overloading, thereby allowing it to carry additional power. This may be

[14] Removing such lines from service is often necessary because operators have few available methods for altering the flow of power in the network. One method, reducing generation levels in one area and increasing them in another, may be useful at times instead of or in addition to removing lines from service. This can be an awkward and uncertain process, however, since changing generation levels takes time, some generators may not be on line and other units may be constrained by maximum (or minimum) generation level limits. In addition, this tends to be an expensive process, since it involves a variation from the operators' preferred pattern of generation, which is generally selected to minimize costs.

accomplished, for example, by enlarging the size of the existing conductors (current-carrying wires).

Sometimes reinforcement of existing lines is not a viable approach, however. In those cases, the best way to eliminate the need for the operating guide is often to build a new line to divert power flows from the overloaded facility. A new high-voltage connection across the interface between eastern and western Wisconsin could eliminate the need for multiple operating guides.

The proposed line, as well as other EHV lines in the Wisconsin Reliability Enhancement (WIRE) Report, would eliminate the need for most of the existing operating guides associated with outages of parts of the existing 345 kV Western interface. One set of operating guides, necessary to prevent overloads when the Arpin-Rocky Run 345 kV line is out of service, would still need to be used, although the power transfer level that would require use of these operating guides would be significantly higher than in today's system. Although a major new transmission connection can be an effective way to eliminate the need for operating guides, other approaches are generally also possible.

Arpin phase angle problem

Among the most significant weaknesses in the existing Wisconsin system is the "Arpin phase angle" problem, in which a large difference in the voltage phase angle between two ends of a transmission line appears when the line trips out of service.

The notion of voltage phase angles in the power system may be obscure to those not familiar with electric power systems. A more detailed discussion appears in the Commission's 1998 Report to the Wisconsin Legislature on the Regional Electric Transmission System.[15] In order to appreciate this problem, however, only the following characteristics need to be understood: (1) the phase angle across a line will tend to increase during high transfers and, particularly, when the line trips out of service; (2) reclosing a line (returning the line to service) when a large phase angle is present across the line can pose a shock to the system that can disturb or damage generators or other equipment; and (3) in general, the only practical way to reduce such large phase angles prior to reclosing the line is to redispatch generation (adjust the generation levels of power plants in the region).

In Wisconsin's power system, this problem can occur during significant west-to-east power transfers, when the Eau Claire-Arpin segment of the existing King-North Appleton line is heavily loaded and then trips out of service. Under these conditions, a large difference in phase angle develops between the two ends of the line. In general, it is possible to reclose lines within a matter of seconds after such an event. Attempting to reclose this line when an excessive phase angle is present, however, could upset or even damage the Weston power plant, south of Wausau. Because of concerns about the Weston plant, present operating policy prohibits reclosing this line until the redispatch process reduces the phase angle to 60º

[15] This report is available electronically from the PSCW at http://psc.wi.us/writings/papers/energy/elecral/transsys.htm.

or less. This process – increasing generation in eastern Wisconsin and reducing generation to the west by a comparable amount – must be carried out gradually.

In order to ensure that this generation redispatch can be accomplished promptly, should a line trip occur, present-day operating policies limit the amount of power that this line is allowed to carry. Even with this limit in place, however, some redispatch may be required, leaving the system vulnerable to a second disturbance while this process is completed. Ideally, the power system should be designed so that such delays could be avoided.

A major new transmission connection between Minnesota and central Wisconsin, such as the proposed line, would reduce this troublesome post-contingency phase angle to the extent that it would no longer delay reclosing the Eau Claire-Arpin segment of the King-North Appleton line.

Other measures could also alleviate this problem. These include installing a large phase-shifting transformer or switched series reactor on the line. Such devices would be installed at a single location, adjacent to existing substation equipment. However, these would be essentially special-purpose measures to allow the existing line to be reclosed at high phase angles, and would not offer all the benefits of a new line, such as improved dynamic and voltage performance, diversion of flow from other lines, reduced power losses, and increased power transfer capability.

Local area problems

In addition to facilitating power transfer from one endpoint to another, a major new transmission line could also help to support the transmission system in the area it crosses. The Arrowhead-Weston applicants did not discuss the potential for providing support to northwestern Wisconsin in the application, probably because this area is served almost entirely by other utilities. Nonetheless, the proposed line could provide significant benefits to this area in the future.

While this issue is not discussed in the application, some information is available that sheds light on this issue. The two major utilities in the area, Northern States Power-Wisconsin (NSPW) and Dairyland Power Cooperative (DPC) filed a report on the transmission system in this area as part of AP-8.[16] This report indicates that these companies believe that currently planned transmission improvements will ensure adequate transmission system reliability through at least 2008. NSPW states that they anticipate no need for major additional reinforcements before 2015, again assuming that currently planned projects are built. With one notable exception, these are all projects that are either currently under construction, involve only rebuilding existing lines, or involve only new substation equipment. The exception is the proposed Chisago-Apple River 230 kV transmission line, which would connect Minnesota and Wisconsin in the St. Croix Falls area. This proposal has faced significant opposition and its ultimate approval is still pending in Minnesota.

[16] AP-8 Technical Support Document D23f; Northern Area (Region 6) Study Report (February 1998).

Even if the Chisago-Apple River line (or a similar line) is built, however, the northwestern Wisconsin system may well require reinforcement after 2015. The proposed Arrowhead-Weston line would facilitate support of this existing system through new connections. Likely locations for new connections include the Stone Lake substation near Hayward, the Osprey substation east of Ladysmith, and a possible new substation to the west of Ladysmith. Additional information from the northwestern Wisconsin utilities would be required to evaluate the importance of these potential interconnection options, which could have an effect on the relative desirability of alternative routes. Additional discussion of this issue appears in Chapter 6.

Transfer Capability for Economic Reasons

Continued growth in firm and non-firm electricity transactions

During the summer of 1999, eastern Wisconsin utilities imported 6.6 percent or 768 MW of their summer peak electric power demand. At the statewide level, Wisconsin imported 4.3 percent of its summer peak electric power demand in 1999. These values are documented in Table 2-8. On the peak day, 872 MW of firm transmission interface capacity was reserved on the Minnesota/WUMS interface and 453 MW was reserved on the Commonwealth Edison (CE)/WUMS interface.[17] The total amount of firm transmission capacity was 1,325 MW. (On any given day this number may change, and on a seasonal basis the firm transmission capacity will be lower than 1,325 MW.)

While these values yield an estimate of the extent of electric power imports necessary to meet peak electric demand in Wisconsin, the values do not represent the complete use of the transmission system. This is because the transmission system is also used during all hours of the day for sales of electricity for resale, where utilities provide wholesale electric power to other utilities, as well as for other outright purchases of non-firm electric energy. Table 2-9 depicts this situation for 1996 and 1998 for electricity generation sales by Wisconsin's large investor-owned utilities.

Table 2-9 indicates that around 25 percent of Wisconsin's total electric energy needs have been met by purchases and sales of firm and non-firm energy using the transmission system. Because this table includes non-firm sales and purchases, the use of a 25 percent value as a proxy for the required use of the transmission system to meet Wisconsin's electricity needs would be an overstatement. The range presented here suggests that between 4 and 25 percent of the state's electricity needs are met during various hours of the day by use of the transmission system. For practical use, a 15 percent value has often been used as a

[17] Values are for contract path flows and not actual facility loadings.

guiding estimate of the amount of electrical needs that Wisconsin must obtain from outside the state utilizing the state's integrated electric transmission system.

Table 2-8 **Assessment of Summer 1999 electric demand and supply conditions**

	1999 Wisconsin	1999 EWU
Peak Demand (MW)		
Peak load forecast [non-coincident]	13,585	11,699
-- Direct load control program	85	65
-- Interruptible load	400	360
-- Net purchases with reserves	190	190
-- Miscellaneous	195	195
Adjusted electric demand	12,715	10,889
Electric Power Supply (MW)		
Generating capacity used for Wisconsin	13,327	10,990
+ IPP capacity	422	422
+ Capacity additions and changes	30	30
+ Net purchases without reserves	396	578
-- Miscellaneous	189	189
Electric power supply	13,986	11,831
Total net purchases (Imports)	586	768
Net imports as percent of peak demand	4.31%	6.56%
Transmission Data		
Firm Interface Capacity Counted for Reserves (MW)		
Resources utilizing MINN/WUMS interface	872	872
Resources utilizing CE/WUMS interface	453	453
Total	1,325	1,325

Source: draft Strategic Energy Assessment, June 2000, PSCW

Should this 15 percent import value persist, the 2,400 MW of new electric demand that may develop in Wisconsin could require an additional 360 MW of firm transmission capacity.[18]

[18] The actual percentage of imports will be determined by the interplay of several economic factors, such as the price of purchased power, the availability of in-state electric generation, and the extent of transmission import capability. The 360 MW estimate is a status quo estimate assuming that 85 percent of new load growth will be accommodated by new generation in the state.

Any expansion of the transmission system's use for other reasons, such as direct retail access, could require additional transfer capability beyond this 360 MW.[19]

Table 2-9 Total 1996 and 1998 electricity generation sales by Wisconsin's investor-owned utilities

	1996 Energy GWH	Percent of Total	1998 Energy GWH	Percent of Total
Sales to ultimate customers	50,731		53,742	
+ Sales for resale	13,055	25%	10,876	21%
- Purchase power	13,556	26%	16,522	32%
= Net generation	50,230		48,096	
+ Miscellaneous	1,420		4,311	
Total Wisconsin	51,650		52,407	

Source: Commission staff; 1996 and 1998 Annual Energy Reports to the Federal Energy Regulatory Commission (FERC)

Increasing congestion on transmission system limiting economic purchases

In addition to economic growth creating a need for additional transfer capability, the amount of traffic on the current transmission system also plays a role. As congestion or constraints on the transmission system limit economic purchases of firm and non-firm power, there can be a need for increased transmission transfer capability.

Table 2-10 depicts the amount of scheduled summer import transactions from the west and south into WUMS just prior to the summer months. Between 1994 and 1996, the transfers from the south were close to zero or negative. After 1996, the amount of scheduled imports has risen from 124 to 397 MW. For transfers from MAPP into WUMS, the data series for 1994 to 2000 indicates a rising import trend through 1998 with a good degree of variability in the 1995 to 1996 and 2000 periods. The combination of the transfers from the south and from MAPP, as shown in Table 2-10, depicts an overall rising import trend, although values appear to have stabilized around 900 MW in the 1998 to 2000 period. This finding indicates that the statewide transmission system has been increasingly used to import power for Wisconsin's needs. The plateau reached in 1998 to 2000 suggests that any further increased use will create future transmission system congestion or constraints.

The values above are for the 1994 to 2000 period and are from MAIN. In February 2000, PSCW staff surveyed the state's major utilities as part of the SEA to obtain an estimate of

[19] Direct retail access, sometimes called retail wheeling, refers to retail customers buying their energy from a competitive marketplace and having it delivered by the local public utility acting as a distribution company. At present this is not allowed in Wisconsin, but it has been the subject of legislative debate.

the expected Summer 2000 scheduled import transactions. This survey indicated that 540 MW are being scheduled from the south into WUMS and that 620 MW are being scheduled on the MAPP to WUMS interface for a total of 1,160 MW. These values are consistent with MAIN's observations and suggest a modest increase in the use of the transmission system.[20] Given current constraints, significantly increased scheduling over the interfaces would appear unlikely without further transmission system improvements in Wisconsin and elsewhere.

Table 2-10 Scheduled summer import transactions from the west and south into WUMS

	South to WUMS MW	MAPP to WUMS MW	Total
1994	-44	547	503
1995	-146	392	246
1996	1	219	220
1997	124	606	730
1998	134	738	872
1999	282	690	972
2000	397	494	891

Notes: South = Illinois, eastern Missouri, Indiana, Ohio, and Kentucky. The 1999 South to WUMS value may be understated by up to 150 MW.
Sources: Summer Transmission Assessment Studies 1995-2000 conducted in May or June, Mid-America Interconnected Network, Inc. (MAIN)

The discussion above concerns scheduled transactions; the following discussion examines MAIN's assessment of transfer capability during summer peak conditions. Table 2-11 displays the first-contingency incremental transfer capability (FCITC) and first-contingency total transfer capability (FCTTC) from northern Illinois and Minnesota into WUMS for the period 1995 to 2000. FCITC values indicate the ability to transfer additional electric power over the transmission system above that already planned; FCTTC values indicate the total amount of expected transfer capability on the transmission system. Both FCITC and FCTTC values indicate of the amount of import capability. Values in Table 2-11 reflect MAIN's assessment of summer peak conditions in May or June of each year.

Table 2-11 shows that MAIN has considered the FCTTC values inadequate for transfers into Wisconsin from both northern Illinois and Minnesota in some years. Such a finding is an indication that the transmission system is beginning to experience congestion or exogenously imposed constraints, such as major generating plant outages. The variability also suggests increasing uncertainty with respect to the use of the transmission grid. However, it is important to note that recent MAIN assessments have found import

[20] The draft SEA, June 2000, indicated an expected 1,204 MW total use for Summer 2001 and 975 MW total use for Summer 2002.

capabilities to be adequate.[21] This is especially the case for the years 1999 to 2000. In addition, results for the year 2000 improved due to completion of the Lockport-Lombard 345kV transmission line in Illinois. Without that facility, MAIN reports that the transfer capability would be inadequate from the south and marginally adequate from the west.

Table 2-11 FCITC and FCTTC import capabilities from northern Illinois and Minnesota into WUMS

	IL to WUMS			MN to WUMS		
	MW FCITC	MW FCTTC	FCTTC Conclusion	MW FCITC	MW FCTTC	FCTTC Conclusion
1995	550	400	Inadequate	200	550	Inadequate
1996	900	900	NA	650	850	NA
1997	1,200	1,200	Adequate	800	1,400	Adequate
1998	400	450	Inadequate	350	950	Adequate
1999	1,100	1,300	Adequate	600	1,100	Adequate
2000	1,500	1,700	NA, likely adequate	700	1,000	NA, likely adequate

Sources: Summer Transmission Assessment Studies 1995-1999 conducted in May or June, Mid-America Interconnected Network, Inc. (MAIN)

Table 2-11 indicates that for transfers from northern Illinois into WUMS, the FCITC values have fluctuated between 400 MW and 1,500 MW. For transfers from Minnesota into WUMS, FCITC values have fluctuated between 200 MW and 800 MW. The fluctuation in these values also suggests an uncertainty about the potential use of the transmission system, although recent trends have been favorable and may be diminishing some of that uncertainty.[22]

When assessing the need for new transmission facilities, it is also important to examine actual usage of existing facilities. Actual data showing just how the transmission system has been limited in the 1997 to 1999 period are contained in Table 2-12. The data in Table 2-12 concentrate on the 345 kV line from King-North Appleton. This high-voltage transmission line is Wisconsin's only major direct link to the MAPP reliability region. Data below provide the actual amount of necessary line loading relief (LLR) with respect to existing power transactions needed to prevent the King-North Appleton line from being improperly used to the point of creating reliability difficulties. The period covered is 1997 to 1999. LLR is the amount of electric power transactions that need to be curtailed, altered, or redispatched to prevent the system limits from being excluded.

[21] MAIN did not provide an adequacy assessment for the year 2000 FCTTC values in its Addendum to the 2000 Summer Transmission Assessment Study. For this reason, Table 2-10 indicates NA, or not available from MAIN. Commission staff has interpreted the results as "likely adequate," however.

[22] The emphasis on uncertainty here is not meant to diminish the fact that transfer capability is heavily dependent on system conditions such as generation dispatch, system topology, parallel path flows, load levels, etc.

Table 2-12 Line loading relief data for King to North Appleton 345 kV transmission line

1997				1998				1999			
#	Date	Time	MW	#	Date	Time	MW	#	Date	Time	MW
1	5/4/97	0.28	50	1	2/6/98	16.30	25	1	3/16/99	5.15	23
2	5/4/97	20.25	95	2	2/7/98	10.30	25	2	5/18/99	22.40	50
3	5/14/97	22.01	35	3	2/24/98	0.18	50	3	5/19/99	17.17	40
4	6/24/97	7.15	110	4	2/24/98	7.15	10	4	6/10/99	22.44	100
5	6/27/97	23.50	95	5	2/27/98	0.24	25	5	6/11/99	22.25	75
6	6/28/97	23.00	75	6	3/13/98	6.23	50	6	7/6/99	13.30	35
7	7/14/97	11.22	25	7	3/18/98	10.30	25	7	7/16/99	20.30	75
8	7/21/97	1.00	40	8	3/30/98	7.30	10	8	7/19/99	22.07	75
9	7/22/97	0.04	40	9	5/20/98	10.40	30	9	9/8/99	18.09	10
10	7/22/97	22.25	120	10	5/22/98	14.15	20	10	12/1/99	7.37	1073
11	7/23/97	21.30	50	11	6/10/98	10.10	60	11	12/1/99	20.50	1424
12	7/25/97	0.10	100	12	6/19/98	7.30	50				
13	7/26/97	0.12	75	13	6/20/98	10.00	30				
14	7/28/97	0.04	25	14	6/22/98	7.00	50				
15	7/29/97	0.10	73	15	6/23/98	6.35	50				
16	8/4/97	23.47	75	16	6/23/98	7.10	70				
17	8/5/97	22.15	75	17	6/24/98	23.30	10				
18	8/6/97	9.40	40	18	6/25/98	14.20	30				
19	8/7/97	8.15	50	19	6/27/98	22.00	70				
20	8/9/97	9.36	25	20	7/1/98	6.00	50				
21	8/11/97	10.06	40	21	7/3/98	6.00	17				
22	8/12/97	1.10	40	22	7/21/98	9.45	20				
23	8/12/97	8.34	95	23	7/29/98	6.30	50				
24	8/12/97	23.10	60	24	8/6/98	7.30	35				
25	8/13/97	6.35	40	25	8/7/98	7.00	75				
26	8/15/97	3.21	130								
27	8/17/97	10.35	25								
28	8/18/97	8.17	50								
29	8/21/97	9.40	35								
30	9/12/97	7.07	35								
31	9/15/97	20.10	85								
32	9/16/97	7.05	200								
33	9/17/97	22.00	80								
34	9/18/97	8.00	50								

1997				1998				1999			
#	Date	Time	MW	#	Date	Time	MW	#	Date	Time	MW
35	9/19/97	22.10	40								
36	9/19/97	6.00	100								
37	9/25/97	8.50	50								
38	9/30/97	7.40	25								
39	10/9/97	6.30	50								
40	10/21/97	9.00	50								
41	10/24/97	22.32	20								
42	11/16/97	22.10	40								
43	11/21/97	22.15	50								

[Source: MAIN website]

Table 2-13 presents a summary frequency analysis of the data in Table 2-12, in order to provide a basic quantitative analysis of the amount of limitations and congestion occurring on the transmission system.

Table 2-13 Trends in line loading relief for the King-North Appleton 345 kV line

Year	Median Block Size (MW)	Maximum Block Size (MW)	Number of LLR Calls Greater Than 0 MW	Number of LLR Calls Equal to 0	Most Likely Time	Most Likely Months	Percent of LLR calls Non-Summer
1997	50	200	43	91	6 a.m.-noon	Aug, Jul, Jun	25%
1998	50	200	25	49	6 a.m.-noon	Jun, Jul, May	40%
1999	75	1,424	11	54	6 p.m.-midnight	Jul, Dec, Jun	54%

In 1997, the median level of MW curtailed was 50 MW.[23] There were 43 instances in which LLR was called for, requiring an actual MW reduction in use for existing purchases and sales using the King-North Appleton line. This is a form of rationing that is required when a facility is operating beyond its capable use. This many calls for LLR usually depicts a situation in which transmission price signals are inadequate to ration the demand, there is poor coordination by transmission system operators, or there may be a need for an expansion in transmission transfer capability. One concern that has been raised is that transmission owners could be operating the system to the advantage of their electric generating plants. In 1997, according to MAIN there were also an additional 91 instances not portrayed in Table 2-13 in which, for reliability reasons, no new transactions could occur. This simply means that the system was so congested that additional new traffic on the transmission system would pose significant reliability risks. Once again such congestion

[23] For institutional and operational reasons, the median level of MW curtailed is not always the best measure of the degree of congestion and constraint; however, the actual number of calls for LLR is a useful indicator of congestion.

depicts a situation in which transmission price signals are inadequate to ration the demand, or MAIN/MAPP coordination was poor.[24] Without better future MAIN/MAPP coordination of scheduled transactions or the use of transmission system congestion pricing, an expansion in transmission transfer capability could be warranted.[25] This conclusion is based on the assumption that existence of the Midwest ISO and the newly formed transmission company will prevent the potential for a transmission owner to operate the transmission system to its advantage. These entities are discussed in the final sections of this chapter.

In 1998, there was less of a need for LLR but still 25 instances in which LLR occurred, requiring an actual MW reduction in use for existing purchases and sales using the King-North Appleton line. The median reduction called was again 50 MW. In 1998, according to MAIN there were also 49 instances not portrayed in Table 2-13 in which, for reliability reasons, no new transactions could occur. While congestion and constraint occurred less often in 1998 than 1997, the data, nonetheless, depict another year in which the use of the transmission system from the west into Wisconsin was still handicapped.

Last year was slightly different. In 1999, LLR occurred just eleven times, requiring an actual MW reduction in use for existing purchases and sales using the King-North Appleton line. The decline in actual calls for LLR in 1999 could be the result of system operators developing more sophisticated operating guides due to the 1997 to 1998 experience or improved coordination between MAIN/MAPP transmission system operators, resulting in reduced over-subscription of the system. Alternatively, the reduction in calls may have been less due to fewer large-scale generating plant outages. Despite the fewer calls for LLR, the median reduction increased from 50 MW to 75 MW in 1999. The largest calls for LLR exceeded 1,000 MW in 1999 versus 200 MW in the 1997 and 1998. The large LLR MW increase in 1999 was due to taking the line out of service for maintenance. In 1999, according to MAIN, there were also 54 instances above those portrayed in Table 2-13 in which, for reliability reasons, no new transactions could occur. This is a value similar to that in 1998. Once again, congestion and constraint occurred in 1999, and use of the transmission system from the west into Wisconsin was handicapped.

The months of March through December are more likely to have calls for LLR (see Figure 2-6), so the problem is almost year-round. The summer months of June through September have the highest incidence of calls for LLR, indicating that the transmission system becomes overburdened during warm and humid or hot days when demand for electricity is at its peak.

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24 MAPP and MAIN have signed a memorandum of understanding preliminary to merging some of their reliability functions.

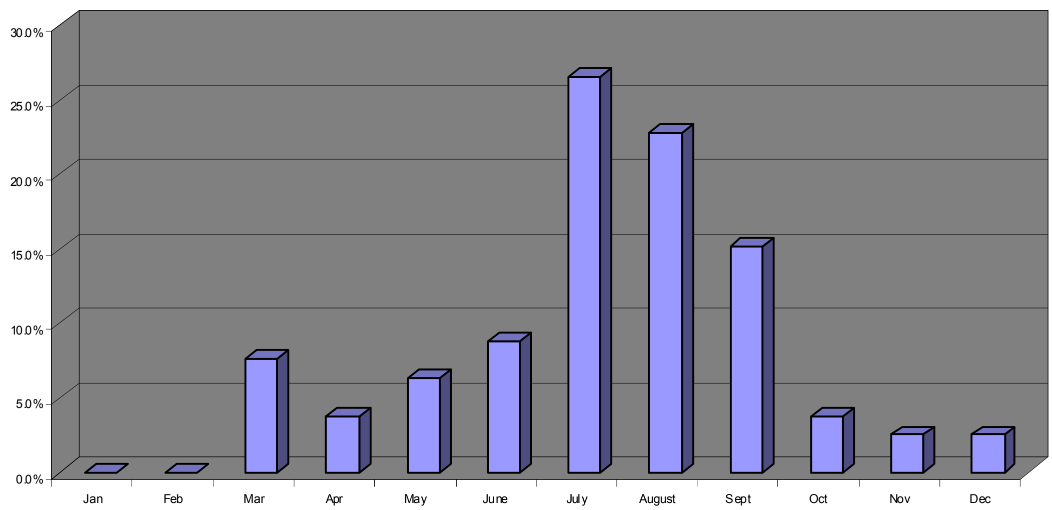
25 It is important to note that congestion pricing on the transmission system is not presently used in Wisconsin; it is used in other parts of the country. As a result, price signals are not allowed to work and the only means of relieving the congestion and constraints is via new transmission facilities. This could change if the Midwest ISO adopts congestion pricing. It has preliminary plans to do so, but any implementation would be years away.

An analysis of data in Table 2-13 shows that LLR is most likely to occur between 6 a.m. and noon. LLR calls also happen with noteworthy frequency between 6 p.m. and midnight due to continuing high demand from the prior day, the expectation of high demand in the later morning and afternoon, and the fact that lower nighttime demand to the west frees additional inexpensive power for export to eastern utilities.

While the calls for 50 to 200 MW of LLR may not seem large relative to total demand in the state of nearly 12,000 MW, any such call for LLR can have large effects on generating unit redispatch throughout the region. For instance, a call for 50 MW of LLR can result in 100 MW of generating capacity being redispatched in the region.[26] Due to the nature of particular sales and purchases, a call for LLR can affect a region's generation with a multiplier effect. Thus, whenever the transmission system becomes congested or constrained, the immediate remedy is usually not insignificant and increased transmission transfer capability may be needed if transmission system pricing signals are not effective in controlling transfer demands.

[26] This range of values is based on WPSC's estimate of a 20 to 30 percent power distribution factor for the Eau Claire-Arpin segment of the King-North Appleton 345 kV line.

Figure 2-6 Monthly distribution of line loading relief calls 1997 to 1999 for King-North Appleton Line



Increased transfer capability may decrease purchased power prices

As prior sections have demonstrated, the transmission system in Wisconsin is prone to calls for LLR and generally is limited in the amount of import capability. These constraints can prevent the flow of lower-cost[27] electric power into Wisconsin, thereby harming ratepayers. Table 2-14 provides the median prices for day-ahead scheduled peak power from Bloomberg.com, an internet reporting service.[28] The data cover the June 1, 1998, to May 31, 1999, period.[29] Table 2-14 excludes the ten highest price spike days. This is the case so Table 2-14 can provide an estimate of peak power market prices during less-constrained operation of the transmission system.

Table 2-14 shows that the median summer price is $32.50 per megawatt-hour (MWh). The fall median price is $21.50 per MWh, and the winter peak and spring median prices are $19.89 and $25.59 respectively.

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27 Measured in pure economic market terms only. This means that only those externalities that have been controlled or monetized via market mechanisms are included in this cost calculation.

28 Power prices here reflect marginal power production costs derived from the costs of fuel and variable operations and maintenance. Prices reported here are not all-in prices which would include the additional effects of any fixed capital costs. This convention is appropriate when examining short-term power markets.

29 This period is chosen in order to use more conservative or higher estimates of potential power prices in subsequent sections of the EIS that examine the cost of power purchases over an expanded transmission system. This is because the corresponding Summer and Fall 1999 prices are lower, $29.84 and $20.59 respectively, than their 1998 counterparts.

Table 2-15 provides estimates of the price of peak power on a day-ahead scheduled basis from the Bloomberg reporting service for the summer of 1998 price spikes. During the ten highest peak power price days, the median price of day-ahead peak power was $268.75 per MWh.[30] Figure 2-7 displays Bloomberg peak power prices for the period June 1, 1998 to May 31, 2000. The figure has been truncated at $375 per MWh for display purposes only.

Table 2-14 MAIN power prices, Bloomberg on-peak index for day-ahead scheduling

MAIN Power Prices Bloomberg On-Peak Index Day Ahead Scheduling			
Summer 1998 - June 1 to Sept. 15		Winter 1998-99 - Dec 16 to Mar 31	
	$/MWh		*$/MWh*
Mean	$36.91	Mean	$20.94
Standard error	$1.97	Standard error	$0.56
Summer median	$32.50	Winter median	$19.89
Mode	$56.25	Mode	$17.63
Standard deviation	$15.54	Standard deviation	$4.56
Minimum	$15.25	Minimum	$14.88
Maximum	$92.25	Maximum	$42.50
Fall 1998 - Sept 16 to Dec 15		Spring 1999 - April 1 to May 31	
	$/MWh		*$/MWh*
Mean	$22.86	Mean	$25.74
Standard error	$0.83	Standard error	$0.61
Fall median	$21.50	Spring median	$25.59
Mode	$18.00	Mode	$24.00
Standard deviation	$6.25	Standard deviation	$3.89
Minimum	$16.00	Minimum	$17.38
Maximum	$48.35	Maximum	$34.00

Note: Analysis excludes 10 highest price spike days.

The prices reported in Tables 2-13 and 2-14 and displayed in Figure 2-7 were likely influenced by the amount of congestion on the transmission network in Wisconsin. In economics, higher congestion and increased import limitations translate into higher effective prices. This was probably the case for the power market in 1998. With the Arrowhead-Weston or similar transmission line project in place, however, fewer constraints would likely occur that prevent the movement of lower cost electric power. With fewer constraints and increased import capability, economic theory predicts that electric power prices could decrease in the state, with the largest declines occurring during price spike days. The size of

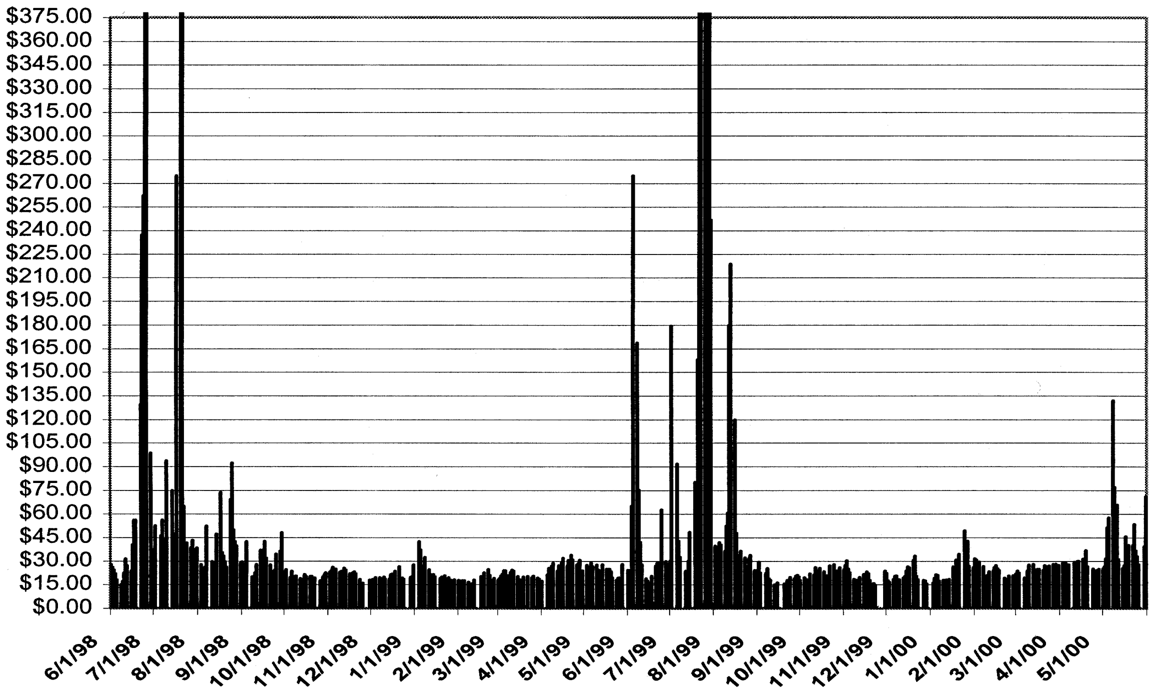
[30] The June 2000 draft SEA indicates that the median price spike for summer 1999 was $345.32 per MWh.

such price decreases is unknown. However, there would be a lower bound beyond which power prices would not likely decline. That lower bound, on a long-term basis, would be represented by the marginal energy costs of a combustion turbine for peaking duty and a combined-cycle unit for intermediate duty. These prices, as developed in Chapter 4 are $32.80 and $19.66 per MWh, respectively. With fewer transmission constraints, power prices would likely decline the most during price spike hours. In 1998, the median peak power price spike was nearly $269 per MWh and in 1999, $345 per MWh. With major new transmission improvements and connections in place, a significant decline from the $269 to $345 per MWh range peak power price could reasonably happen. With substantially reduced import constraints and a well functioning wholesale power market, such price spike prices could eventually fall to levels near the established lower bound levels.

Table 2-15 MAIN power price spikes, summer 1998, Bloomberg on-peak index for day-ahead scheduling

	Weekday	Date	Price $/MWh
1	Monday	22-June	$130.00
2	Tuesday	23-June	$237.50
3	Wednesday	24-June	$262.50
4	Thursday	25-June	$1,025.00
5	Friday	26-June	$400.00
6	Monday	29-June	$98.75
7	Friday	10-July	$93.75
8	Friday	17-July	$275.00
9	Monday	20-July	$1,650.00
10	Tuesday	21-July	$562.50
Mean			$473.50
Median			$268.75

Figure 2-7 MAIN electricity prices $/MWh for day ahead scheduling June 1, 1998 to May 31, 2000



Source: Commission staff, Bloomberg Reporting Service.

An expanded transmission system could address prospective horizontal market power issues in WUMS

Presently, when the transmission system becomes constrained or congested the relevant market size from an anti-trust perspective narrows to the geographic region of WUMS. In the 1997 Federal Energy Regulatory Commission (FERC) merger docket of Alliant Energy Corporation, the FERC considered the WUMS region to be an "island system," meaning that the relevant operational wholesale market was limited to the WUMS area. When a market becomes so limited, utilities or other players with a large market share or concentration can obtain leverage over the prices being paid in that market. In essence, a large electric generating firm in a narrow competitive energy market can influence prices to its advantage and everyone else's detriment. In economics, such leverage is referred to as horizontal market power and is policed by federal and state anti-trust law. One way to reduce such horizontal market power is to eliminate or minimize the extent to which a constrained transmission system is preventing electric power imports. This could involve an expansion of the transmission system such as the proposed Arrowhead-Weston line.

Table 2-16 depicts the expected competitive marketplace in WUMS for the year 2003 when the Arrowhead-Weston Transmission Project is proposed to be in service. The analysis presumes further deregulation of both the wholesale and retail electricity markets.[31] In such a system, electric generating units in WUMS would be competing with one another. In such a market, the usual analytical output measure is total generation capacity.

The analysis uses these additional assumptions: All 300 MW of the SEI Wisconsin, LLC project in Neenah, which began operation in May 2000, are assigned to WEPCO due to existing contract. Similarly, only 150 MW of the 450 MW RockGen LLC project in Dane County have been assigned to WP&L for delivery into WUMS due to an existing contract, with the remaining 300 MW placed into the open market for delivery to WP&L's affiliated utilities in Iowa which are not in the constrained WUMS area. Other changes reflected in Table 2-15 include: a 95 MW transfer of MGE's share of the Kewaunee Nuclear Power Plant to WPSC; 135 MW of new combustion turbine capacity for WEPCO at its existing Germantown site; and 83 MW of new combustion turbine capacity for MGE located in Marinette. For the existing transfer capability, 1,080 MW is used. With an Arrowhead-Weston or similar type of major new transmission project in place, the amount of transfer capability is increased by 2,200 to 3,280 MW. No incumbent utility or generator controls the firm transfer capacity over the interfaces, assuming the presence of a strong ISO that can prevent the exercise of any vertical market power. The analysis in Table 2-16 also requires the expected Badger Generating 1,050 MW unit in Southeastern Wisconsin to be operational by 2003. In addition, the capacity brought in by increased transmission transfer capability is likely to come from a variety of potential energy providers outside WUMS, so no market share is designated for any particular provider.[32]

Using the current transmission system configuration without a major new transmission line installed, Table 2-16 shows 14,239 MW of potential generation available in WUMS in 2003 with WEPCO having a market share of 45 percent. The Herfindahl-Hirschman Index (HHI) produces a value of 2538.[33] The HHI statistic is sanctioned by federal anti-trust law to measure potential horizontal market power effects.[34] At a level of 2538, the market portrayed in Table 2-16 is considered highly concentrated with a high likelihood of significant adverse competitive consequences. Federal anti-trust law considers HHI values above 1800 to be indicative of highly concentrated markets.

With a major transmission project in place adding 2,200 MW of extra import capability, Table 2-16 shows 16,439 MW of potential generation available in WUMS in 2003 with

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[31] This assumption is made due to electric industry restructuring developments in the country. For instance, by 2003, competitive retail markets for electricity should be operational in Illinois and Michigan. The analysis in this section is prospective since the competitive market retail delivery of electricity is presently not allowed in Wisconsin, although there has been regulatory commission and legislative debate.

[32] This also assumes that a strong ISO prevents undue control of the expanded import capability.

[33] The HHI value is calculated by summing the squares of market share. For instance (20*20) + (30*30) + (50*50) = 3800.

[34] 1992 Horizontal Merger Guidelines, U.S. Department of Justice and Federal Trade Commission, as revised April 8, 1997.

WEPCO having a market share of 39 percent. The HHI produces a value of 1904. This 1904 is within striking distance of the expanded WUMS market being considered only a moderately concentrated market in which the potential for adverse competitive effects is reduced. The practical implication from this analysis is that the presence of a major new transmission line could help mitigate both wholesale and retail horizontal market power. The presence of a major transmission line and the associated increase in transfer capability could assist in further electric industry restructuring, such as the implementation of direct retail access.

Table 2-16 Amount of market concentration in 2003

Amount of Market Concentration in 2003 if Retail Market Competition Existed with Present Constrained Transmission System in WUMs	**MW**	**Market Share**	**HHI**
WEPCO	6333	44.5%	1978
Alliant-WP&L	2256	15.8%	251
WPS	2111	14.8%	220
MGE	611	4.3%	18
WPPI & others	498	3.5%	12
Imports	1080	7.6%	0
SkyGen	300	2.1%	4
Badger Gen	1050	7.4%	54
	14239	100%	2538
Amount of Market Concentration in 2003 If Retail Market Competition Existed with 2200 MW of New Transmission Transfer Capability			
WEPCO	6333	38.5%	1484
Alliant-WP&L	2256	13.7%	188
WPS	2111	12.8%	165
MGE	611	3.7%	14
WPPI & Others	498	3.0%	9
Imports	3280	20.0%	0
SkyGen	300	1.8%	3
Badger Gen	1050	6.4%	41
	16439	100%	1904

[Source: Reliability reports filed with the Commission]

Federal and state policies affecting electric industry restructuring

During the 1990s both state and federal policy shifted toward an increased reliance on competitive market forces in the electric industry. Most of the changes have been at the wholesale level, although such changes are prerequisites for any further move toward using competitive market forces in the retail delivery of electricity. Prior to the 1990s the electric industry operated primarily in a regulatory mode. For the most part utilities focused on generation and transmission needs in their respective service territories; although, since the 1960s, the utilities have also planned and constructed facilities for interconnections and regional reliability considerations.

Changes in federal and state policy, however, have created new circumstances in which the scale of the required reliability must increase, potentially translating into the need for additional large-scale transmission facilities. Changes in federal and state policy have brought about increasing amounts of regional brokering, trading, and exchanging of electric power over the current electric transmission system, which has limited transfer capability. The objective of these policy changes has been to lower utilities' electric power production costs, thereby benefiting ultimate retail customers with lower electricity rates. The expanded amount of wholesale trading resulting from recent federal and state policy initiatives also increases the complexity, from an engineering and institutional perspective, of running and maintaining a reliable electric transmission system. Any future move toward using increased competitive market forces in the retail delivery of electricity is likely to have similar effects. While federal and state policy changes can translate into the need for more transmission facilities, it is difficult to enumerate the exact magnitude or scale of the required expansion.

The particular federal and state policies bringing about an increased need for transmission facilities are: FERC Order 888, FERC Order 889, and 1997 Wis. Act 204. FERC Orders 888 and 889, were issued in April 1996, and established the foundation necessary to open and develop competitive bulk power markets in the United States. These two FERC orders provided for non-discriminatory open-access of transmission services by public utilities and for a fair transition to competitive markets with respect to stranded cost recovery. FERC Order 888 required that all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce must file open access non-discriminatory transmission tariffs and functionally unbundle wholesale power services. FERC Order 889 required that all public utilities establish or participate in an Open-Access Same-Time Information System (OASIS) and comply with standards of conduct designed to prevent employees of a public utility engaged in wholesale power marketing from obtaining preferential access to pertinent transmission system information. In reviewing developments since 1996, the FERC has indicated that: "Orders 888 and 889 [have] required a significant change in the way many public utilities have done business for most of the century."[35]

[35] Page 17, Regional Transmission Organizations, Notice of Proposed Rulemaking, Docket RM99-2-000, May 13, 1999, Federal Energy Regulatory Commission, Washington, D.C.

Moreover, "the availability of the [open-access] tariffs and information about the transmission system has fostered a rapid growth in dependence on wholesale markets for acquisition of generation services."[36]

The practical effect of these changes has been a significant increase in flows on transmission lines that form the regional high-voltage network. This effect has been particularly pronounced during the late-night and early-morning hours, when low electricity demand makes low-cost generation available for sale to distant utilities. Not only have flows on power lines increased, but the increased distance between parties to a transaction has the effect of allowing the transaction to simultaneously flow over many paths between the transacting parties. These so-called parallel flows can use line capacity that Wisconsin utilities may be counting on to gain access to power purchases from the west.

1997 Wis. Act 204, which became effective May 12, 1998, created statutes governing the building and operating of non-regulated wholesale merchant electric power plants in Wisconsin. Prior to the enactment of this law, the construction of such plants was not legal. Wholesale merchant power plant developers are now free to construct a generating facility without economic regulation and sell the attendant electric power in deregulated wholesale electric power markets. Such sales will utilize the state's electrical transmission system. Increasing amounts of such sales, under certain engineering circumstances, can translate into the need for additional transmission capacity. Increasing transmission capacity can also lead to more wholesale transactions.

Potential buyers from merchant power plants in deregulated wholesale electric power markets include Wisconsin utilities, regional and national electric power brokers and marketers, as well as out-of-state utilities. 1997 Wis. Act 204 was enacted, in part, to enhance reliability in the generating and transmission of electric power to Wisconsin citizens. The law relies on competitive market forces for the timely construction of electric power facilities, rather than the regulatory planning paradigm practiced when the state prepared biennial Advance Plans.

Under 1997 Wis. Act 204 two wholesale merchant power plants have already received approval from the Commission. The first plant was approved in November 1998 and is to be located in the township of Christiana in Dane County. This electric power plant will be comprised of three combustion turbines producing up to 450 MW of peak electric power. RockGen Energy LLC will be constructing the facility. The facility is under contract to sell firm peak electric power to Alliant Energy. Non-firm power from the RockGen facility may also be sold into the open market, another use of the transmission system. The RockGen facility is expected to start producing power in about 2001 depending on the outcome of ongoing lawsuits filed by project opponents.

[36] Ibid.

The second plant was approved in January 1999 and is located in the township of Neenah in Winnebago County. This electric power plant is comprised of two combustion turbines producing up to 300 MW of peak electric power. SEI Wisconsin, LLC, a unit of the Southern Energy Company, built this facility, which began commercial operation in spring of 2000. The SEI plant is under contract to sell firm and non-firm electric power to WEPCO.

Recently, an application for another new wholesale merchant power plant has come forth and is being reviewed by the Commission. On December 28, 1999, Badger Generating Company, LLC, proposed a 1,050 MW facility in Racine or Kenosha County. This Badger Generating facility would be comprised of four combined-cycle units. A combined-cycle unit uses both gas and steam turbines to produce power. The gas turbine is a conventional combustion turbine, and the steam turbine uses the hot air exiting the gas turbine to produce power. The Badger Generating plant is expected to be operational in 2003. Should the Badger Generating plant be approved, Wisconsin's electrical system reliability would be enhanced to the extent the facility sold either firm or non-firm power to the state's utilities or allowed more electricity imports over the southern interface. The size and location of the Badger Generating facility may also have an effect on the need for the Arrowhead-Weston Transmission Project. This is discussed further in Chapter 4.

One additional important provision of 1997 Wis. Act 204 is the requirement that utilities in the state transfer control over their transmission facilities to an independent entity. This could either take the form of transferring operational control of transmission facilities to an ISO or completely divesting transmission facilities to an independent transmission owner. Wisconsin utilities were required to commit to taking one of these actions by June 30, 2000.

An ISO is an organization formed to operate a transmission system in a manner that ensures non-discriminatory access to the transmission system for all electricity market participants while ensuring stable, reliable operation over large areas. This is intended to alleviate a number of present-day concerns. These include the belief that integrated utilities may operate their transmission systems in a way that favors their own generation and that entities that can monitor and control the transmission system over a large region are necessary to maintain system reliability.

At present, nearly all of Wisconsin's major utilities have committed to joining the newly formed Midwest ISO, and will transfer control of their transmission facilities to the Midwest ISO. Those major utilities that have not yet made such a commitment are engaged in negotiations intended to lead to joining the Midwest ISO. Headquartered in Indianapolis, the Midwest ISO presently has members with transmission facilities in states from Pennsylvania to the Dakotas.

ATCo was created in accordance with the provisions of 1999 Wisconsin Act 9 as a single purpose transmission company.[37] Six utilities in Wisconsin, the Upper Peninsula of

[37] See Wis. Stat. § 196.485.

Michigan, and a small portion of Illinois have announced their intention to divest their transmission facilities to ATCo.[38] Wisconsin Public Power Incorporated (WPPI) does not own any transmission facilities but it will obtain an ownership share in the new company through a cash contribution. It is expected that several municipal utilities and distribution cooperatives may also elect to contribute their transmission facilities to the new company. Members will own ATCo in proportion to the value of the transmission assets or cash they contribute.

1999 Wisconsin Act 9 requires the new transmission company to be a member of the Midwest ISO. The ATCo will be a single zone under the Midwest ISO's transmission tariff, although the rate charged to the utilities in their existing service territories will move a single average rate over a five-year period to mitigate rate impacts.

ATCo will be responsible for providing transmission service and operating the transmission facilities it owns under the auspices of the Midwest ISO. It will also plan for system expansion and improvements.[39]

Effects of midwest ISO on transmission use and congestion

Presently, almost all transmission service within and between MAIN and MAPP is provided under the terms of the individual transmission owners' Open Access Transmission Tariffs (OATT). Under the terms of these OATTs, each transmission owner along the path of a power transaction levies a separate transmission charge.[40] These separate, cumulative charges create an effect known as rate pancaking. Pancaking affects the economics of power transactions because it increases the transmission costs of power transactions that pass through multiple transmission systems. Pancaking reduces the effective geographic size of regional power markets and reduces the number of competitors that can effectively compete in sub-regional markets, such as eastern Wisconsin.

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[38] Edison Sault Electric Company; Madison Gas and Electric Company; South Beloit Water, Gas and Electric Company; Wisconsin Electric Power Company; Wisconsin Power and Light Company; and Wisconsin Public Service Corporation.

[39] For a complete description of the structure and functions of ATCo, see the August 18, 2000 application of ATCo in "In the Matter of the Organization of American Transmission Company LLC," Commission docket 137-NC-100.

[40] The exception is that non-firm transmission service in MAPP is provided under MAPP Service Schedule F. The charges for transmission service for Schedule F transactions are based on an engineering model of the MAPP system, which estimates the impacts that each transaction has on each transmission owner's facilities. Only a single charge is assessed to any transaction.

When the Midwest ISO becomes operational, on November 1, 2001, all transmission service in Wisconsin will be provided under the Midwest ISO OATT.[41] The Midwest ISO OATT will be a "grid-wide tariff" because individual transactions anywhere in the Midwest ISO will only be assessed a single charge for transmission service. In other words, there will be no rate pancaking. There will be two general effects of the Midwest ISO tariff. First, the market for electric power and energy will become considerably larger geographically and more competitive because transactions can be made over longer distances with only a single transmission charge. Customers within the Midwest ISO will pay the same transmission rate regardless of where the generation source is located. Secondly, the demand for transmission service will tend to increase because longer distance transactions will become cheaper.

Congestion pricing or locational marginal pricing effects on transmission line congestion

Another significant factor that affects transmission system use and competition is the methods that are employed to manage congestion on the transmission system. Congestion occurs when the amount of transmission service that is requested for a specific transmission path exceeds the capacity of the transmission system.

The capacity of the transmission system is determined through the use of engineering models and is known as Total Transmission Capacity (TTC). A portion of this transmission capacity is set aside for emergency use and to provide resiliency for the transmission system when unexpected events occur. The remaining Available Transfer Capacity (ATC) can be used to transmit power from sellers to buyers. For most of the transmission system, the amount of ATCOexceeds the amount of transmission service that has been requested. However, there are many transmission paths where requests for transmission service exceed the ATC. These paths are known as constrained interfaces. Transmission paths into Wisconsin from the south and from the west are both considered constrained interfaces.

If relative transmission costs for longer distance transactions fall and the demand for transmission service increases, it is likely that there will be greater congestion. Additional interfaces will become constrained and existing constrained interfaces are likely to become more congested. Congestion on the transmissions system must be actively monitored and managed so that the system operates within its physical limits. Otherwise, the reliability of the grid is threatened.

There are several approaches to relieving and managing constraints. On a longer time horizon, new transmission facilities can be planned and built. On a short-term basis MAIN and MAPP employ a system of congestion management called Transmission Loading Relief

[41] Dairyland Power Cooperative (DPC) may not become a member of the Midwest ISO until implications relating to its tax-exempt status are resolved. It will continue to provide service under its shared transmission system agreement in any event.

(TLR)[42]. This chapter earlier provided examples of the transmission LLR on the MAIN system and the amount of congestion in Wisconsin during 1997 to 1999. Under TLR, when a constrained interface becomes overloaded, transactions that are flowing over the constrained interface are cut back until the flows return to safe levels.

One criticism of TLR is that it does not take into account the economic interests that various transmission customers may have in having a particular transaction either continued or curtailed. That is, some transmission users place a higher value on transmission service at various times than other customers, and yet TLR does not take this into consideration when transmission curtailments are made. In its final order (FERC Order 2000) on Regional Transmission Organizations (RTO), FERC requires RTOs to use market mechanisms to manage transmission congestion.[43] Several market-based methods are employed elsewhere in the United States and in other countries for relieving transmission congestion.

One-market based approach for relieving constraints on a short-term basis is known as locational marginal pricing (LMP). Under LMP, transmission charges are based upon on the difference in electricity prices on each side of a constrained interface. Rather than the administrative action of TLR, LMP uses transmission prices to reduce the demand for transmission service in order to match it with ATC. Because it takes market prices into account, LMP is considered to be more economically efficient than TLR. However, LMP requires the existence of a power exchange so that energy prices on each side of constrained interfaces are available to the transmission operator and market participants. A power exchange operated by Automated Power Exchange, Inc., began operation in the spring of 2000 with CE as the trading hub. In order to implement an LMP congestion management approach for the MAIN / MAPP interface, another power exchange trading hub would need to be established in Minnesota on the western side of the current transmission constraint.

Another market-based method for relieving constraints on a longer-term basis involves the sale of Financial Transmission Rights (FTR), which allow the holder to transmit across a specific constrained interface, or "flowgate." FTRs could be bought or sold and thus transmission users that place the highest value on the use of a constrained interface should be able to purchase FTRs from other transmission users. When facility expansions of constrained interfaces are planned, the additional FTRs could be auctioned. Such an auction would provide a market test as to whether the value to transmission users of the additional transmission capacity that results from the proposed expansion exceeds the construction cost.

The Midwest ISO is expected to select a method to manage congestion sometime in the fall of 2000.

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[42] MAPP employs a slightly different system known as LLR for firm transactions.

[43] 89 FERC ¶ 61,285.

New transmission company

The new transmission company that is to operate in Wisconsin, known as ATCo, is being formed in response to 1999 Wisconsin Act 9, which established the framework for a new transmission company in the state and created incentives for certain utilities to transfer their transmission facilities to the transmission company.[44]

Under its statutory charter, the transmission company:

> *…has as its sole purpose the planning, constructing, operating, maintaining and expanding of transmission facilities that it owns to provide for an adequate and reliable transmission system that meets the needs of all users that are dependent on the transmission system and that supports effective competition in energy markets without favoring any market participant.*

Beginning January 1, 2001, ATCo, will take over ownership and maintenance responsibilities, plan for local transmission improvements and build new facilities in the area of the transmission system facilities it owns. It may also operate other utility transmission systems that it does not own through lease arrangements. As is true of all transmission utilities in Wisconsin, the transmission company is required by state law to join the Midwest ISO (MISO)[46] and will operate its transmission system and administer the MISO transmission tariff subject to MISO oversight. In short, the transmission company would have essentially all the transmission-related responsibilities and powers that the integrated utilities now have.

The transmission company will be initially owned by the utilities that contribute their transmission facilities to it in exchange for ownership shares. It will not be an "independent" transmission company because these owners will continue to own and operate generation facilities. In addition, municipal and cooperative utilities will be able to acquire ownership shares in the new company by contributing cash.

Like WPSC and other present-day integrated electric utilities, the transmission company would be a regulated, for-profit public utility. The transmission company will have the same eminent domain privileges with respect to transmission lines that the integrated utilities have

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[44] 1999 Wisconsin Act 9, which became effective on October 29, 1999, allowed utility holding companies to obtain relief from the "asset cap" in Wis. Stat. § 196.795(6m), which limits the fraction of holding company assets that non-utility businesses can represent. For the purpose of this law, "transmission facilities" are generally defined as those facilities designed for operation at a voltage above 50 kV.

[45] Wis. Stat. § 196.485(1)(ge).

[46] To be precise, Wis. Stat. § 196.485(2) requires transmission utilities to either transfer control of their transmission facilities to an independent system operator or divest their transmission facilities to an independent transmission owner (i.e. independent of power market participants in this region). As a practical matter, participation in the Midwest ISO appears to be the only way to satisfy this requirement at present, since no independent transmission owner or alternative ISO has emerged in this region.

today. The Commission will continue to have oversight of transmission facility construction and siting. The FERC will have sole jurisdiction to regulate the prices, terms and conditions of the transmission service provided by the transmission company. The FERC will allow the transmission company, like today's integrated transmission-owning utilities, to earn a regulated return on its capital investment through its transmission tariff.

The main differences between the transmission company and today's integrated utilities will be that the transmission company will cover a larger area and that its sole focus will be providing transmission service. In principle, this should eliminate any motivation to manipulate transmission system operation or planning to benefit or harm particular generation owners. This is viewed as a significant benefit by independent power producers (IPP) and small utilities that currently depend on transmission service provided by the large transmission-owning utilities. In addition, incorporating multiple transmission systems into a single company should improve the quality of coordinated, statewide transmission system planning. One disadvantage is that the transmission company may find it harder to carry out integrated system solutions that involve generation or energy efficiency improvements as well as transmission, than is the case for today's integrated utilities.

At present, among major transmission owners in the state, WEPCO, WP&L, MGE, and WPSC have all applied to the Commission to transfer their transmission facilities to the transmission company. The Commission expects to issue an order in this case in December, 2000, before the transmission company's expected start of operation on January 1, 2001. MP initially participated in transmission company formation activities, but has since withdrawn.

Neither NSPW nor DPC, the two primary transmission owners in western Wisconsin, plans to participate in the transmission company at present.

As noted above, the transmission company will not buy or sell power, but will only charge other power market participants a FERC-regulated rate for transmission service used to deliver the power. However, even if one or both of the applicants continue to have an ownership stake in the proposed line, rather than transferring it to the transmission company, ownership should confer no special advantages in terms of access to generation sources near the line. Specifically, the applicants should not, simply by virtue of their geographical location, be able to use the proposed line to purchase low-cost western power and sell it at a profit to the east. This is because, under federal transmission regulation, any prospective ultimate wholesale electricity customer should be able to purchase power directly from any generator, and arrange separately for regulated transmission service to deliver the power.